FINAL
TECHNICAL SUPPORT
DOCUMENT

CENTRALIA PLANT
REASONABLY AVAILABLE CONTROL TECHNOLOGY
(RACT)

SWAPCA 97-2057

Final

December 8, 1997

Centralia Plant RACT Technical Support Document
for Regulatory Order SWAPCA 97-2057

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COMMON ABBREVIATIONS

BACT	Best Available Control Technology
CCOFA	Close Coupled Over-fire Air
CF	Capacity Factor
CMC	Centralia Mining Company
CO	Carbon Monoxide
CO_2	Carbon Dioxide
EPA	U.S. Environmental Protection Agency
EPA-Region 10	U.S. Environmental Protection Agency - Region 10
FLM	Federal Land Managers (Forest Service or National Park Service)
ESP	Electrostatic Precipitator
FGD	Flue Gas Desulfurization
FS or USFS	U.S. Forest Service, U.S. Department of Agriculture
HAP	Hazardous Air Pollutant
LAER	Lowest Achievable Emission Rate
lb/MBtu	Pound(s) per Million British thermal units
LNB	Low NO_x Burners
MW	Mega-Watt(s) (one million watts)
NAAQS	National Ambient Air Quality Standard
NAS	National Academy of Sciences
NESCAUM	Northeast States for Coordinated Air Use Management
NO_x	Oxides of Nitrogen
NPS	National Park Service, U.S. Department of the Interior
O_2	Oxygen
OAPCA	Olympic Air Pollution Control Authority
PCHB	Pollution Control Hearings Board
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 Φm in size
$PM_{2.5}$	Particulate Matter less than 2.5 Φm in size
PSAPCA	Puget Sound Air Pollution Control Agency
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
SAAQS	State Ambient Air Quality Standard
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SOFA	Separate Over-fire Air
SWAPCA	Southwest Air Pollution Control Authority
TAP	Toxic Air Pollutant
UBC	Unburned Carbon
WDOE	Washington Department of Ecology

Section 1.0

REGULATORY BACKGROUND

This section is focused on regulatory issues and is divided into three subsections: (1) Plant Regulatory History, (2) Applicable Regulations and (3) Conclusions. The Centralia Plant was constructed in the early days of the formation of the Southwest Air Pollution Control Authority, the Washington Department of Ecology and the Environmental Protection Agency. Rules and policies were not fully developed in the early days of the agency; this is not to say though, that there were no rules. The rules that were in place were not as definitive as those that exist today. In addition, there have been improvements in technology since the plant was originally constructed. The activities and dates for many of the events (physical and regulatory) at the Centralia Plant are important from a regulatory perspective. Section 1 provides a chronology of the permitting activities and ongoing compliance issues related to the Centralia Plant. Section 2 identifies regulatory citations, legal proceedings, and other perspectives that provide insight into the processes and limits that have been or will be established for the Centralia Plant. Section 3 provides definitive statements in regards to specific issues and presents a position taken by SWAPCA in regards to these issues.

1.1 Plant Regulatory History

Regulation 1 of the Southwest Air Pollution Control Authority (SWAPCA) adopted December 17, 1968 provided for, in part, issuance of an Order of Approval for the construction and installation of new sources, established a general opacity limit of No. 2 on the Ringelmann Chart, established requirements for reporting of upsets or breakdowns, and identified an appeal process for Orders issued by SWAPCA.

Regulation 2 of SWAPCA adopted October 29, 1969 provided for, in part, registration of air contaminant sources and related control equipment, ambient air quality standards for sulfur dioxide and particulate matter, and odor nuisance limitations. The sulfur dioxide ambient standard was established at: 0.75 ppm averaged over 15 minutes, measured once in any 8 hour period; 0.5 ppm averaged over 1 hour, measured once in any 4 consecutive days; 0.1 ppm averaged over 24 hours, measured once in any 30 consecutive days; and 0.05 ppm averaged over 30 days, with unlimited frequency of monitoring. It also established that no person shall allow, cause, let, permit, or suffer the emission of an air contaminant from any source which contains, as measured in the stack, gaseous sulfur compounds containing oxygen, calculated as sulfur dioxide, of more than 1500 parts per million (ppm) by volume. Additional requirements were identified for sources which exceeded this limit which included, in part, demonstration of no exceedence of the ambient air quality standard and installation and operation of ambient air monitors. In addition, a particulate matter standard was established stating no person shall discharge from any single source particulate matter which exceeds, for fuel or refuse burning equipment, 0.10 grain for each standard cubic foot of exhaust gas corrected to 12% carbon dioxide (CO_2).

Notice of Construction (L-1) for the Centralia Plant was received by SWAPCA in a letter dated October 27, 1969. Approval for construction of the Centralia Plant Units #1 and #2 was provided by SWAPCA in a letter dated November 7, 1969 based on a review of the application. Particulate matter was the only pollutant for which controls were proposed in the Notice of Construction. Performance data were as set forth in the particulate matter control equipment contract with the manufacturer, Koppers Company, Inc., as presented in the electrostatic precipitator (ESP) design specification sheet (ES11). Selected conditions and operating requirements from the third column of the design specification sheet included: Btu content of fuel - 6681 Btu/lb; coal percent sulfur (wt) - 0.85%; flue gas 7,730,000 lb/hr and 40,400 acfs; ash to precipitator - 151,200 lb/hr; inlet grain loading - 10.72 gr/scf; outlet grain loading - 0.06 gr/cf; precipitator guaranteed efficiency - 99.44%. Each steam generator was rated at 5,168,000 lb/hr steam at 2990 psig and 1005EF (700 MW). Facility operating parameters and control equipment parameters presented in the Notice of Construction application were stated as binding on the applicant in the SWAPCA approval.

An air quality study was performed under contract with Washington State University for the Centralia Plant. A total of 35 study sites were selected for use in the examination of the air quality within an approximately 1,000 square mile area surrounding the Centralia Plant. Initially, 12 sites were selected for the first year's pre-operational study beginning in October, 1969. The number of sampling sites was increased to approximately 29 in early 1970. Additional sites were added to the study network later in 1970 and 1971.

Unit #1's initial turbine roll occurred on August 6, 1971. Unit #1 commenced operation in September 1971 and Unit #2 in September 1972. Upon startup of Unit #1, difficulties were encountered with proper operation of the Koppers ESPs. Opacity and grain loading at the stack discharge exceeded state standards as well as manufacturer's guarantees during the boiler performance guarantee operations and testing. In a letter dated March 8, 1972, SWAPCA indicated to the Centralia Plant that, to date, no information had been submitted to SWAPCA demonstrating compliance with the approved particulate matter performance standard emission limit of 0.06 grains per standard cubic foot (gr/scf). The letter requested power production data and testing results from the point of initial startup through the current month. Data was received by SWAPCA in a letter dated March 24, 1972 which indicated the unit was still in a testing phase and that emissions were above the state standard and SWAPCA emission limit and that a precipitator improvement program was underway. Modifications were made to the ESPs in the summer of 1972 with compliance expected from the units upon restart after the summer outage in August. On August 4, 1972 SWAPCA provided approval to restart Units #1 and #2 after the outage but limited operations to not exceed 300 MW except for approved incremental increases based on testing data. On September 14, 1972 SWAPCA approved operations at 400 MW and on October 6, 1972 SWAPCA approved operations at 500 MW. On December 11, 1972 a formal Regulatory Order was issued to the Centralia Plant in accordance with Article III of Regulation I of the SWAPCA rules approving operation of each unit up to 500 MW and a particulate matter emission limit not to exceed 0.06 gr/scf.

On January 21, 1972, Washington Department of Ecology (WDOE) filed a revision to Washington Administrative Code (WAC) 18-400-040 to include an SO_2 emission limit of 2000 ppm with no averaging period identified. Provisions were made for all new sources constructed after July 1, 1975 limiting SO_2 emissions to 1000 ppm.

In a letter dated March 16, 1973 the Centralia Plant submitted a Notice of Construction (L-49) to SWAPCA for installation of an SO_3 gas conditioning system to help improve the performance of the Koppers ESPs. Notice of Construction (L-50) dated March 23, 1973 was submitted to SWAPCA for installation of a second set of ESPs in series with the existing ESPs, to initially be used as a pilot test to improve performance of the particulate matter emissions controls to allow operations at full power. A Regulatory Order approving Notice of Construction L-49 for the SO_3 gas conditioning system was issued on March 29, 1973. A Regulatory Order approving Notice of

Construction L-50 for the second set of ESPs was issued on April 13, 1973. Operation of each unit was still limited to 500 MW as provided under the Regulatory Order issued December 11, 1972. A Regulatory Order was issued by SWAPCA on April 26, 1973 requiring testing to provide additional information with regards to the SO_3 gas conditioning system and detailed the required reporting as a result of the testing. A Regulatory Order was issued by SWAPCA on May 4, 1973 requiring testing and reporting for the ESP pilot test program. A Regulatory Order was issued by SWAPCA on May 22, 1973 modifying dates and operating conditions as specified in the previous ESP pilot test Regulatory Order. On June 11, 1973, SWAPCA issued a Regulatory Order authorizing Unit #1 at generation levels up to 700 MW while maintaining emissions at or below 0.06 gr/scf. On November 8, 1973, Executive Order EO 73-09 was issued by the Governor of Washington, Daniel Evans, authorizing Unit #1 and Unit #2 generation at its maximum capabililty in order to have an average output of 1,200 MW. This Executive Order was issued to help offset projected energy shortfalls for the Pacific Northwest. The Executive Order had a termination date of May 1, 1974.

Notice of Construction L-50R dated January 3, 1974 was submitted to SWAPCA to provide final design information on the second set of ESPs (Lodge-Cottrell). A Regulatory Order approving this Notice of Construction was issued on February 7, 1974. Conditions in the Approval included performance in accordance with the Lodge-Cottrell guarantee; stack sampling with noncondensible particulate matter under all conditions at an initial ceiling not to exceed 0.04 gr/scf, as corrected to 12% CO_2; additional stack sampling to establish that continued operations shall maintain emissions below 0.06 gr/scf; the above conditions to be demonstrated no later than three months after startup of the equipment. On February 22, 1974, SWAPCA revised the February 7, 1974 Regulatory Order of Approval to clarify language regarding the stipulations as they relate to the construction and installation time period.

On March 25, 1974 SWAPCA issued Administrative Order 74-38 to the Centralia Plant to perform daily high load compliance particulate matter testing for Unit #2 within 36 days of the date of the Order. On May 2, 1974, Administrative Order 74-38 was amended upon request by the Centralia Plant to extend the test period to not exceed ten days commencing May 6, 1974.

The ambient air and meteorological monitoring program being conducted by Washington State University for the Centralia Plant was terminated on December 31, 1974. The objective of the five year monitoring program was to gather baseline data and post operational data for the plant to be able to ascertain the impact, if any, of plant emissions on the area surrounding the plant.

As of January 17, 1975, the SO_3 gas conditioning system had been physically disconnected at the Centralia Plant. Daily testing for particulate matter as performed under contract with WSU was discontinued on February 28, 1975 and, thereafter, testing was to be performed on a semi-annual basis.

Lear-Siegler opacity monitoring correlation data for the Centralia Plant was submitted to SWAPCA in a letter dated July 11, 1975. Normal operations of the Centralia Plant were identified as 2 to 10% opacity with the actual limit established at 20%.

The Centralia Plant disagreed with the authority of SWAPCA to establish an emission limit more stringent than the state standard for particulate matter. Initial approval of the Plant by SWAPCA occurred under SWAPCA Regulation I, Section 3.03(b) which required SWAPCA to not issue an "Approval of Construction" unless the information demonstrates, among other things, that the equipment as installed will not violate emission standards and the equipment incorporates "advances in the art of air pollution control". The term "advances in the art" is the term that predates "best available control technology" (BACT). A discharge concentration of 0.06 gr/ft^3 was required in the Centralia Plant equipment specification and guaranteed by the precipitator vendor. This concentration was repeated in several Orders of Approval issued by SWAPCA, including those on December 11, 1972, April 13, 1973, April 26, 1973, May 4, 1973, May 23, 1973, June 11, 1973, and February 7, 1974. The emission limit was established consistent with "advances in the art" to not allow for degradation of control equipment and ensure meaningful emission reductions as intended under the Clean Air Act. SWAPCA attempted to include the 0.06 gr/ft^3 particulate matter limit in an Order of Authorization to Operate issued to the plant, but the Centralia Plant questioned the authority of SWAPCA to create a document referred to as an Order of Authorization to Operate. All references to this emission limit were removed from the Order of Authorization to Operate and the name was changed to Equipment List. The underlying legal authority for the 0.06 gr/ft^3 limit remained with the Orders of Approval noted above.

On December 21, 1976, WDOE revised WAC 173-400-040(6), as codified in the 1977 edition of the Washington Administrative Code. This revision removed reference to the 2000 ppm SO_2 limit for existing sources and left in place the emission limit of 1000 ppm, but did not specify an averaging period or sampling time period. As a result of this revision, the rule would be applicable to all sources, existing and new. SWAPCA did not adopt this regulation language until rule changes effective December 18, 1979.

In a letter dated April 7, 1978, the Centralia Plant provided details to SWAPCA of the continuous opacity monitoring project undertaken by the Centralia Plant to comply with WAC 173-400-120, 40 CFR Part 51, Appendix P, Sections 3, 4 and 5 promulgated October 6, 1975, and 40 CFR Part 60 Appendix B, Performance Specification 1.

The Centralia Mining Company (CMC) began mining new areas of the coal mine in February 1978. Portions of these new areas produced coal with a sulfur content greater than the coal previously mined and, on average, a content of approximately 1 percent had been recorded by a number of samples. There was uncertainty if these sulfur contents translated to a sulfur dioxide emission in excess of the 1000 ppm standard. The Centralia Plant agreed to undertake at least one test each day of the flue gas from one of the Centralia Plant units for a period of one to three months using EPA Method 6. Centralia Plant personnel became concerned about the Plant's ability to meet the 1000 ppm sulfur dioxide emission limit over an averaging period less than 30 days and, after discussions with SWAPCA and WDOE, a test program was initiated to correlate coal sulfur content with sulfur dioxide emissions. Testing was conducted in August through October 1978. Several Method 6 samples indicated sulfur dioxide emissions greater than 1000 ppm. However, this testing was conducted for the purpose of establishing a correlation between coal sulfur content and stack sulfur dioxide emissions, not for compliance determinations. These samples were not integrated and were taken at a time when the averaging time and the number of samples to be integrated was not defined in rule. In October 1978, SWAPCA, WDOE and Centralia Plant personnel met and agreed to use monthly weighted averages of coal sulfur and a 96 percent conversion factor to determine whether the 1000 ppm sulfur dioxide emission limit was being met.

In a letter dated November 29, 1978, the Centralia Plant submitted results from the operational performance test for the continuous opacity monitoring program for Units #1 and #2. Results indicated the system for both units operated within specified performance parameters during the 168 hour operational test period.

Sulfur dioxide from each unit's stack was initially limited to 1,500 ppm (SWAPCA Regulation 2 Section 5.01, adopted October 29, 1969) based on integrated samples monitored for a minimum period of 15 minutes. The air regulations were renumbered by Ecology in about 1976 from WAC Title 18 to WAC Title 173. However, this standard was revised by SWAPCA in rule revisions adopted on December 18, 1979 to 1,000 ppm for all sources with no averaging period. In addition, all point sources were required to use reasonably available control technology (RACT) which may be determined for some sources or source categories to be more stringent than the emission limitations of the regulation. Visible emissions were established as not to exceed 20% opacity for more than three minutes in any one hour period. Emission standards for hazardous air pollutants were established through adoption by reference of the federal standards contained in 40 CFR Part 61 as of April 26, 1979. Pollutants identified were asbestos, beryllium, beryllium rocket motor firing, mercury and vinyl chloride. Revisions were also made to include provisions for excess emissions during startup and shutdown and reporting of such events.

The SWAPCA General Regulations (SWAPCA 400) were revised as adopted on October 18, 1981 to provide a registration fee of $50.00 for each registered facility and a New Source Review fee of $75.00 per Notice of Construction.

A 60 minute averaging period with correction to 7% oxygen was incorporated into WAC 173-400-040 by WDOE in revisions to the rule on April 15, 1983 and was adopted into SWAPCA 400-040 on March 20, 1984. Neither of these rules provided for a sampling time period. A new section was added to the SWAPCA rules (SWAPCA 400-220) that allowed for appeals of Agency decisions to the SWAPCA Board of Directors in addition to the Pollution Control Hearings Board (PCHB).

In addition to better coal management (simple blending) in July 1986 by the Centralia Mining Company (CMC) to ensure more uniform coal supply to the plant, additional changes were made to the coal sampling procedure to provide better data on sulfur content in the coal. Since initial operation, the sulfur content in the coal had increased to an average of about 0.95%. Calculations made by the Centralia Plant indicated that SO_2 emissions above 1000 ppm may be experienced when coal sulfur content exceeds about 1.05%. Previous samples were taken at 4 hour intervals manually by operators from the feed belts, upstream of the surge silo. The new system automatically diverted a measured sample from the in-feed belts at a set volume interval and performed an analysis. This analysis was performed using a LECO SC-132 sulfur determinator. The automatic sampling system was installed at a cost of $450,000 in December 1986.

SWAPCA issued Order of Violation SWAPCA 87-934 on August 26, 1987 to the Centralia Plant for 74 daily violations of the 1000 ppm / 60 minute average standard, based on coal analysis results. A civil penalty of $1000.00 per day was assessed (maximum allowable at that time) for each day of violation. The penalty was suspended upon satisfactory implementation of an as-burned coal sampling program based on regular samples every 20 minutes; implementation of an SO_2 emission sampling program to correlate emissions with coal sampling; and no additional violations of the SO_2 emission standard within one year of the date of the Order.

On September 14, 1987, the Centralia Plant submitted a Petition for Stay of Order to SWAPCA and a Notice of Appeal to the Pollution Control Hearings Board. In addition, an Affidavit of A. H.

Seekamp was included with the Petition for Stay which detailed the cost of the imposed requirements from the Order of Violation to be $3.15 million. This cost was concluded to be excessive for the data which was to be provided under stipulations provided in the Order of Violation.

On September 21, 1987 SWAPCA issued Stay of Order of Violation SWAPCA 87-934-STAY based on the Centralia Plant's request to be provided an opportunity to perform ambient sampling to determine if a violation of the ambient air quality standard has occurred. The Order provided an 18 month stay of the penalty, and required a coal sampling program and emissions testing program pending installation and operation of ambient air samplers. One year's worth of data was to be collected to provide a basis for the Centralia Plant's request for an exemption from the 60 minute average provision of the 1000 ppm standard.

On October 14, 1987 the Pollution Control Hearings Board issued PCHB NO. 87-219 Order of Dismissal Subject to Reopen in response to the Motion to Hold Appeal in Abeyance and to Withdraw its previous Motion of Stay in regard to the SWAPCA Order of Violation 87-934. SWAPCA did not oppose the Motion for Abeyance and Stay.

On October 15, 1987, the Centralia Plant filed a Petition for Exemption from the 60 minute averaging interval under SWAPCA 400-040(6). Centralia Plant submitted an amendment to the Petition dated December 24, 1987 which provided SWAPCA with results of ambient air modeling in an effort to demonstrate that the state and federal ambient air quality standards were not violated by emissions from the Centralia Plant. Centralia Plant's modeling was not sufficient to demonstrate to the satisfaction of SWAPCA that the ambient air quality standards were not being violated. Therefore, monitoring or actual sulfur dioxide emissions were necessary to document the level of emissions from the Centralia Plant.

On February 24, 1988 SWAPCA issued Order, Withdrawal of Stay and Modification of Order of Violation SWAPCA 88-934 which required the Centralia Plant to: (1) Install SO_2 and O_2 monitors by September 1, 1988 at the Centralia Plant. These monitors were to be performance tested with acceptable results by October 1, 1988; (2) Install ambient air monitors at three sites approved by SWAPCA to be in operation by October 1, 1988; (3) Perform coal washing and blending to provide a cleaner more uniform coal supply to the boilers; (4) Perform a study to determine the technical and economic feasibility of utilizing lime injection multiple burner (LIMB) technology to reduce SO_2 emissions and submit results to SWAPCA by November 1, 1989; and (5) Establish an interim SO_2 limit of 1000 ppm corrected to 7% O_2 on a weekly average.

EPA Region 10 issued a Notice of Violation on March 11, 1988 for violation of the SO_2 state emission standard. This Notice of Violation was based upon EPA's belief that the SIP included a 60-minute averaging time on a dry basis with respect to the 1000 ppm SO_2 emission limit.

The Centralia Plant submitted an Application for Variance to the SWAPCA Board of Directors in a letter dated April 22, 1988. The Variance was required by SWAPCA to ensure that a formal variance proceeding was complied with as provided in SWAPCA 400-150 and RCW 70.94.181. The variance was requested for an exception to the 60-minute averaging time specified in SWAPCA 400-040(6) for the 1000 ppm SO_2 emission limit.

An Amended Petition for Review of Action of the Environmental Protection Agency was filed with the Ninth Circuit Court of Appeals by the Centralia Plant dated May 12, 1988.

EPA Region 10 issued a revised Notice of Violation to Centralia Plant in a letter dated June 3, 1988. This revised Notice of Violation superseded and vacated the previous Notice of Violation of March 11, 1988. This Notice of Violation alleged that the Centralia Plant had exceeded the 1000 ppm SO_2 emission limit based upon EPA's belief that emissions, if actually measured using the compliance methodology set forth in the SIP, could exceed the 1000 ppm emission limit. EPA noted in the letter that they prefer to support the SWAPCA enforcement lead on this matter rather than pursuing a separate federal action.

In response to EPA's concerns, SWAPCA granted the Centralia Plant a temporary variance on July 14, 1988 with issuance of SWAPCA 88-934B Variance and Modification of Order allowing the Centralia Plant to determine compliance with the 1000 ppm emission limit for sulfur dioxide using a weekly, rather than hourly, averaging time. The term of the variance was from May 5, 1988 through November 25, 1989, or until a practical means of compliance became known, available, and implementable. In addition, it required the Centralia Plant to modify its plans to conduct ambient monitoring by October 1, 1988 and to correct continuous emissions monitoring data to a dry basis, and other minor modifications of the Order. Subsequent to having issued the Notice of Violation, EPA indicated it acquiesced to SWAPCA's modified Order and the temporary variance, and indicated that it would defer to SWAPCA with respect to determining compliance at the Centralia Plant.

Initial certification tests of the newly installed SO_2 monitors were performed in August and September, 1988. Testing was performed in accordance with procedures identified in 40 CFR 60, Performance Specifications 2 and 3.

In a Request for Renewal of Variance dated September 31, 1989 (mis-date, actual 9/1/89) the Centralia Plant requested that the existing variance be renewed for one year from November 25, 1989 to November 25, 1990 to allow for time to complete negotiations and enter into a Consent Decree for further ambient air monitoring and confirming dispersion modeling.

The Technical and Economic Feasibility Study of Limestone Injection Multiple Burners report dated October 17, 1989 was received by SWAPCA on October 24, 1989. SWAPCA issued a letter dated January 24, 1990 approving the study as satisfactory completion of SWAPCA 88-934 Section 4.

On October 24, 1989, SWAPCA held a public meeting for the purpose of receiving any testimony that would result in reasons why the variance should not be continued. No comments were received in direct opposition to the variance or variance renewal. EPA Region 10 was involved in developing a Consent Decree but was not part of the variance approval process. WDOE was supportive of renewal of the variance. SWAPCA granted the Centralia Plant a variance renewal on October 24, 1989 with issuance of SWAPCA 88-934C Variance Renewal and Modification of Order allowing the Centralia Plant to continue to determine compliance with the 1000 ppm emission limit for sulfur dioxide using a weekly, rather than hourly, averaging time. The term of the variance was extended from May 25, 1988 until the earlier of: (a) November 25, 1990, or (b) the date on which a practical means for adequate abatement or control of sulfur dioxide emissions, to the extent necessary to comply with the 60 minute averaging requirement, becomes known, available, and implementable. In addition, the Order required the Centralia Plant to install ambient meteorological monitoring equipment at the Centralia Plant so as to be used for dispersion modeling. Centralia Plant was required to model ambient SO_2 levels in the vicinity of the Centralia Plant using the Rough Terrain Dispersion Model and the meteorological data collected near the plant. Modeling was to be completed with a report to SWAPCA by December 21, 1990. The original Order was modified to require ambient monitoring at only two sites instead of three.

The Lear-Siegler opacity monitors were replaced with Thermo Environmental Instruments, Inc. (TEI) opacity monitors at the same locations in July and August of 1990.

In a Request for Further Renewal of Variance dated August 27, 1990 Centralia Plant requested that the existing variance be further renewed for one year from November 25, 1990 to November 25, 1991 to allow for additional time to complete negotiations and enter into a Consent Decree for further ambient air monitoring and dispersion modeling.

The TEI opacity monitors experienced ongoing problems after installation and were removed and returned to the manufacturer. The old Lear-Siegler RM4 opacity monitors were reinstalled and made operational in early October 1990.

In a letter dated October 31, 1990 the Centralia Plant notified EPA Region 10, WDOE, and SWAPCA of an exceedence of the Washington State one-hour ambient air standard of 0.4 ppm SO_2 at the Crawford Mountain monitor on August 12, 1990.

On September 18, 1990, SWAPCA held a public meeting for the purpose of receiving any testimony that would result in reasons why the variance should not be continued. No comments were received in direct opposition to the variance or variance renewal. EPA Region 10 continued to be involved in developing a Consent Decree but was not part of the variance approval process. WDOE was supportive of the renewal of the variance. SWAPCA granted the Centralia Plant a variance renewal on November 9, 1990 with issuance of SWAPCA 90-934D Variance Renewal and Modification of Order allowing the Centralia Plant to continue to determine compliance with the 1000 ppm emission limit for sulfur dioxide using a weekly, rather than hourly, averaging time. The term of the variance was extended from May 25, 1988 until the earlier of: (a) November 25, 1991, or (b) the date on which practical means for adequate abatement or control of sulfur dioxide emissions, to the extent necessary to comply with the 60 minute averaging requirement, becomes known, available, and implementable. In addition, the Order required Centralia Plant to install ambient meteorological monitoring equipment at the Centralia Plant so as to be used for dispersion modeling. Ambient meteorological monitoring was to continue through September 30, 1991. The Centralia Plant was required to model ambient SO_2 levels in the vicinity of the Centralia Plant using the Rough Terrain Dispersion Model and the meteorological data collected near the plant. Modeling was to be completed with a report to SWAPCA by December 21, 1991. The Order continued to include requiring ambient monitoring at only two sites instead of three.

In a letter dated November 9, 1990, SWAPCA clarified the enforcement policy regarding the use of the SO_2 continuous emission monitor (CEM) data to provide information for making enforcement judgement decisions related to good operation and maintenance practices, thereby protecting the ambient air quality of the region. The letter indicated that the short term sulfur dioxide exceedences as measured by a continuous in-stack monitoring device may be determined by using the average value of the data collected for sixty consecutive minutes. The sixty consecutive minutes was to start on the hour and continue for the one hour time period. The calculated average for any sixty minute value was to have at least forty one-minute data points during the sixty minute period for such determination. The value was to be rounded to the nearest one part per million sulfur dioxide. The SWAPCA regulations at that time allowed for limited excursions of the SO_2 standards for such things as coal variability. The allowance was for up to sixty consecutive one-minute average periods of excessive emissions in any 24-hour period. In order to relate this appropriately to a policy that addressed emission units with continuous monitoring devices, it was determined that two unique periods of sixty minute averages exceeding the 1000 ppm limit would be allowed before a "Day of Violation" for the specific emission unit was established. The derivation of the number of days per month of allowable excess emission was from the WDOE Enforcement Policy. The policy allowed for excursions of the sulfur dioxide emission standard for five percent of the days in the month, after which a major excess emission, or violation, is determined to have occurred and penalties would be assessed. When used in conjunction with the determination of a "Day of Violation", a major violation for an emission unit would be determined to have occurred whenever excess emissions from any normal maintenance or operation exceeds two days in any calendar month. The magnitude of the penalty assessed would be determined by the magnitude, duration and frequency of the excessive emission. Once a violation month was established, all days in excess of two unique periods in a day where there are sixty consecutive minutes were to be used in establishing the penalty portion of the violation.

In a letter dated December 4, 1990, the Centralia Plant notified SWAPCA that replacement opacity monitors had been identified and ordered. The new proposed monitors were manufactured by United Sciences Inc. (USI) model 500C. Specifications and data sheets were provided to SWAPCA. In a letter dated December 27, 1990 Centralia Plant notified SWAPCA that the new opacity monitors were placed into service on December 19 and December 21 for Unit #1 and Unit #2, respectively. Additional work remained to be completed to reprogram the Odessa Engineering Data Acquisition System to be able to log the opacity data from the new monitors. Certification tests were scheduled for February 1991.

In a letter dated February 6, 1991, the Centralia Plant notified SWAPCA that coal sulfur variability was now sufficiently under control to permit the Centralia Plant to comply with the Washington State Implementation Plan (SIP) requirement of sixty minute averaging. Accordingly, they attached a draft SWAPCA 90-934E Withdrawal of Petition, Surrender of Variance, and Order. Comments were made by SWAPCA and EPA that excessive exceedences could be allowed under the proposed language without being a violation. In response to this concern, the Centralia Plant added a proviso under Section III.B to clarify that nothing in this methodology was deemed to authorize exceedences in violation of law. In a letter dated April 5, 1991, Centralia Plant provided to SWAPCA two signed copies of the final for SWAPCA 90-934E of which SWAPCA signed and approved, dated April 5, 1991. Items in the Order were identified as: (1) Section III.1 is terminated; (2) Section III.2 (continuous emission monitoring) shall continue indefinitely; (3) Section III.3 (meteorological monitoring) is terminated except that all data shall be submitted to SWAPCA; (4) Section III.4 (ambient modelling) is terminated; (5) Section III.5 (ambient monitoring) is terminated except that all data shall be submitted to SWAPCA; (6) Section III.6 (ambient air quality) is terminated; and (7) Section III.7 and the First Modified Order are terminated.

In a letter dated July 2, 1991, EPA Region 10 provided comments on the currently signed Withdrawal of Petition SWAPCA 90-934E dated April 5, 1991. The EPA indicated concern over the method of compliance determination in that the Centralia Plant could be in exceedence status for up to 14% of the time and not be in violation.

In a letter dated June 16, 1992, the Centralia Plant notified SWAPCA that new replacement oil mist eliminators had been installed on the Unit #1 Main Turbine Lube Oil System during the May-June, 1992 outage. Replacement of the Unit #2 mist eliminator was scheduled for the 1993 outage.

In a letter dated January 15, 1993, the Centralia Plant notified SWAPCA that on January 5, 1993 a 72 minute period occurred in which sulfur dioxide emissions from the Centralia Plant Unit #1 were in excess of 1,000 ppm. The exceedence was attributed to the CMC personnel not providing timely notification that the sulfur content in the coal as delivered to the Centralia Plant was above 1%. By the time the notification was made to Centralia Plant personnel, a substantial amount of higher sulfur coal had been sent to the coal silos. The only way to remove the coal from the silos is to burn through it. Unit #2 did not experience an exceedence because at the time of the silo loading, Unit #2 silos were near full and did not receive an appreciable amount of the higher sulfur coal. Upon notification Centralia Plant personnel took immediate action to stockpile the higher sulfur coal and switch the silo supply to the lower sulfur coal. CMC revised its operating procedures regarding coal sulfur levels and notification procedures to ensure this incident was not repeated.

In a letter dated June 28, 1993, the Centralia Plant notified SWAPCA that a new replacement oil mist eliminator for Unit #2 had not been installed due to problems encountered with the Unit #1 mist eliminator. The problems on the Unit #1 mist eliminator had been resolved but not in sufficient time to place an order for Unit #2. The Unit #2 mist eliminator was to be installed as subsequent forced outages allow.

The LAND Combustion SO_2 and O_2 continuous emission monitoring systems (CEMS) were installed and certified in 1988. In 1994, the LAND systems were replaced by a new ANARAD CEMS as part of the 40 CFR Part 75 (Acid Rain Program) compliance requirements. These systems were served by an Odessa Engineering Data Acquisition and Handling System (DAHS) to perform data capture, reduction, and reporting. A new ENERTEC DAHS was installed as part of the new ANARAD CEMS package. In a letter dated May 23, 1995, the Centralia Plant requested that the Odessa Engineering DAHS be replaced with the ENERTEC DAHS for the opacity monitors.

The Centralia Plant made a RACT submittal to SWAPCA in a letter dated September 26, 1994. A final RACT Order (SWAPCA 95-1787) for the Centralia Plant was issued on August 25, 1995. The RACT Order was appealed by a citizen to the Pollution Control Hearings Board (PCHB) in an appeal dated September 25, 1995. A letter of agreement dated March 20, 1996 was signed between SWAPCA and the Centralia Plant setting forth the terms and conditions under which SWAPCA would withdraw Regulatory Order SWAPCA 95-1787. SWAPCA issued Regulatory Order - Order of Withdrawal SWAPCA 96-1872 dated March 20, 1996 which withdrew the original RACT Order (SWAPCA 95-1787) and included a compliance schedule for submittal of additional information and studies. The withdrawal as provided in SWAPCA 96-1872 was deemed by the PCHB to be an amendment of the original RACT Order SWAPCA 95-1787 and therefore the PCHB ruled the original RACT Order was still in effect. At the SWAPCA Board of Directors meeting on September 18, 1996, Resolution 1996-8 was approved which unconditionally withdrew RACT Order SWAPCA 95-1787 and SWAPCA 96-1872. Further motions were filed by a citizen with the PCHB and on October 31, 1996, the PCHB issued Order of Dismissal PCHB No. 96-252 which determined that SWAPCA's Board Resolution 1996-8 constitutes a lawful, unconditional withdrawal of SWAPCA's original RACT Order and as a consequence, the PCHB dismissed the appeal. A petition to reconsider was filed by a citizen with the PCHB on November 12, 1996 and on November 15, 1996 the PCHB issued an Order Denying Reconsideration, PCHB No. 95-106 & 96-252.

In a letter dated January 23, 1996, EPA (Acid Rain Division) determined that the Centralia Plant Acid Rain Continuous Emissions Monitoring Systems Certification Application was complete and that the ANARAD monitoring systems and ENERTEC DAHS were approved as meeting the 40 CFR Part 75 requirements. In a memo dated March 4, 1996, SWAPCA was notified by EPA (Acid Rain Division) of the system certification and in a letter dated March 5, 1996, SWAPCA approved the proposed change-out of the DAHS for the Centralia Plant for purposes of Part 75.

Northwest Environmental Advocates (NWEA) filed a lawsuit against EPA, WDOE, and SWAPCA in July 1996 in federal district court. Several issues were raised by NWEA in its lawsuit, including concerns about the Centralia Plant=s SO_2 emissions. With regard to the Centralia Plant issues, all parties agreed to file a stay of further proceedings until November 30, 1997.

The Centralia Plant notified SWAPCA in a letter dated February 4, 1997 that it had contracted with Dr. John Samet of Johns Hopkins University to perform a health risks study of Centralia Plant=s emissions of SO_2, NO_x and particulate matter.

The first submittal of a second round of RACT information was provided to SWAPCA by the Centralia Plant on April 30, 1997. A second submittal dated May 13, 1997 was made to SWAPCA which contained information on contaminants of concern and qualitative analysis of control technologies for individual pollutants. A third submittal dated June 20, 1997 was made to SWAPCA which included further information, especially about emission control systems and costs. A fourth submittal dated August 25, 1997 was made to SWAPCA which included revisions to information previously submitted as well as supplements to Appendices A and D and added new Appendices L (Health Risk Assessment) and M (SEPA Checklist).

In a letter dated April 18, 1997, EPA-Region 10 notified the Centralia Plant that the application for Phase I Acid Rain Permit for NO_x Early Election was complete and a permit was issued. The permit would be effective 10 days after the close of the 30-day public comment period provided there were no public comments.

On June 17, 1997, the Centralia Plant notified SWAPCA that plant emissions exceeded the 1000 ppm SO_2 limit for three consecutive one-hour periods in the early morning. SO_2 emission concentrations were reported as 1045, 1019, and 1032 ppm, one hour averages. As provided in SWAPCA 90-934E, a violation is not triggered until two exceedence days are recorded in a month. This three hour exceedence constitutes one exceedence day. The exceedence was the result of high sulfur coal in the storage piles being fed into the coal silos during Unit #2 startup. Normally coal is supplied directly from the mine and sulfur analysis is performed on-line. During startup of Unit #2 coal was supplied from a storage pile where the sulfur content was not readily known. Because of the high SO_2 levels indicated in the control room, the operators began to introduce fuel oil into the boiler and reduce the coal flow. This action resulted in lowering the SO_2 stack concentration below the 1000 ppm limit where emissions remained throughout the rest of the startup.

A public workshop was held in Centralia, Washington on August 5, 1997 to receive public input on the process of establishing RACT air emission limitations for the Centralia Plant.

In a letter dated August 11, 1997 from the Centralia Plant to SWAPCA, the Centralia Plant requested that SWAPCA determine that the emission limits to be set by the RACT proceedings for the Centralia Plant also achieve "Best Available Retrofit Technology" (BART) emission limits. Additional information relative to the Navajo Generating Station and Hayden Station settlements regarding visibility issues were provided as the basis for the request.

A lawsuit was filed in King County Superior Court on December 13, 1996 by a citizen seeking a decision to overturn the PCHB dismissal of his earlier appeal. In Superior Court in King County on August 20, 1997 a hearing was held in regards to the authority of SWAPCA to withdraw a regulatory order and the ability of the PCHB to dismiss a case upon such withdrawal. The court ruled on September 5, 1997 (No. 96-2-18870-1SEA) that the PCHB acted properly in its dismissal of the earlier case and that SWAPCA did have the authority in general to withdraw an order under both the express powers granted to it by statute, and by the powers implied in any agency to do what it is required to do.

1.2 Regulatory Citations

The purpose of this section is to identify pertinent or applicable regulatory citations that provide a basis for, or insight into, how SWAPCA arrived at the conclusions presented in the next section. Citations to other processes, such as best available control technology (BACT) or prevention of significant deterioration (PSD), should not be construed as applicable to the RACT process but were only used for comparison purposes.

1. "Reasonably available control technology (RACT)" means the lowest emission limit that a source is capable of meeting by the application of control technology that is reasonably available when considering technological and economic feasibility (Ref. 1, RCW 70.94.030(19)).

2. RACT is an emission limit or level, not a particular technology (Ref. 2, SWAPCA 400-030(68).

3. The determination of RACT has flexibility in that it is decided after reviewing all the facts and circumstances applicable to the facility. Establishing RACT can either be a category-wide or a case-by-case process where RACT at one plant can be different than RACT at another plant (Ref. 2, SWAPCA 400-030(68).

4. RACT is determined by taking into account the impact of the source upon air quality, the availability of additional controls, the emission reduction to be achieved by the use of additional controls, the impact of additional controls on air quality, and the capital and operating costs of the additional controls (Ref. 2, SWAPCA 400-030(68)).

5. In determining RACT, local air authorities are to consider RACT determinations and guidance made by the U.S. Environmental Protection Agency, other states and local authorities for similar sources, and other relevant factors (Ref. 1, RCW 70.94.154(5)).

6. Section 108(h) of the Federal Clean Air Act requires the Administrator of EPA to make information regarding emission control technology available to the States and to the general public through a central database (RACT/BACT/LAER Clearinghouse). Such information is to include all control technology information received pursuant to State Implementation Plan provisions requiring permits for sources, including operating permits for existing sources. This includes all determinations made in accordance with the Washington SIP and other state SIPs for RACT, BACT or LAER determinations, not just those in non-attainment areas.

7. Source specific RACT determinations may be performed, among other reasons, when an air quality problem, for which the source is a contributor, justifies such an action (Ref. 1, RCW 70.94.154(2)(d)).

8. The PSD program was initiated in response to a court order in the early 1970s interpreting general language in the Clean Air Act requiring EPA to "protect and enhance" air quality (Ref. 28, pp. 1-8). The 1977 Clean Air Act Amendments created Part C of the Act entitled Prevention of Significant Deterioration of Air Quality. Sections 160-169, 42 U.S.C. ' ' 7470-7479. The PSD provisions are intended to help maintain good air quality in areas which attain the national standards, and provide special protection for national parks. The Centralia Plant was constructed in 1971 and 1972 which predates the PSD rules. There have been no major modifications at the

facility which would trigger PSD since the plant was constructed, therefore, no PSD review or permit of the Centralia Plant has been performed or issued.

9. 40 CFR 52.21(i) "Review of major stationary sources and major modifications - Source applicability and exemptions" (1) No stationary source or modification to which the requirements of paragraphs (j) through (r) of this section apply shall begin actual construction without a permit which states that the stationary source or modifications would meet those requirements. ... (4) The requirements of paragraphs (j) through (r) of this section shall not apply to a particular major stationary source or major modification, if; (i) Construction commenced on the source or modification before August 7, 1977. The regulations at 40 CFR 52.21 as in effect before August 7, 1977, shall govern the review and permitting of any such source or modification; or (ii) The source or modification was subject to the review requirements of 40 CFR 52.21(d)(i) as in effect before March 1, 1978, and the owner or operator: ... (8) The Administrator may exempt a stationary source or modification from the requirements of paragraph (m) of this section, with respect to monitoring for a particular pollutant if: (i) The emissions increase of the pollutant from the new source or the net emissions increase of the pollutant from the modification would cause, in any area, air quality impacts less than the following amounts: Carbon monoxide - 575 Φg/m^3, 8-hour average; Nitrogen dioxide - 14 Φg/m^3, annual average; Particulate matter - 10 Φg/m^3 of PM-10, 24-hour average; Sulfur dioxide - 13 Φg/m^3, 24-hour average; Ozone [footnote- No de minimis air quality level is provided for ozone. However, any net increase of 100 tons per year or more of volatile organic compounds subject to PSD would be required to perform an ambient impact analysis including the gathering of ambient air quality data.]; Lead 0.1 Φg/m^3, 3-month average; Mercury - 0.25 Φg/m^3, 24-hour average; Beryllium - 0.001 Φg/m^3, 24-hour average; Fluorides - 0.25 Φg/m^3, 24-hour average; Vinyl chloride - 15 Φg/m^3, 24-hour average; Total reduced sulfur - 10 Φg/m^3, 1-hour average; Hydrogen sulfide - 0.2 Φg/m^3, 1-hour average; Reduced sulfur compounds - 10 Φg/m^3, 1-hour average; or (ii) The concentrations of the pollutant in the area that the source or modification would affect are less than the concentrations listed in paragraph (i)(8)(i) of this section."

10. 40 CFR 52.21(2)(i) "Major Modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act. (ii) Any net emissions increase that is significant for volatile organic compounds shall be considered significant for ozone. (iii) A physical change or change in the method of operation shall not include: ... (h) The addition, replacement or use of a pollution control project at an existing electric utility steam generating unit, unless the Administrator determines that such addition, replacement, or use renders the unit less environmentally beneficial, or except: (1) When the Administrator has reason to believe that the pollution control project would result in a significant net increase in representative actual annual emissions of any criteria pollutant over levels used for that source in the most recent air quality impact analysis in the area conducted for the purpose of Title I, if any, and (2) The Administrator determines that the increase will cause or contribute to a violation of any national ambient air quality standard or PSD increment, or visibility limitation.

11. 40 CFR 52.21(32) "Pollution Control Project" means any activity or project undertaken at an existing electric utility steam generating unit for purposes of reducing emissions from such unit. Such activities or projects are limited to: (i) The installation of conventional or innovative pollution control technology, including but not limited to advanced flue gas desulfurization, sorbent injection for sulfur dioxide and nitrogen oxides controls and electrostatic precipitators; (ii) An activity or project to accommodate switching to a fuel which is less polluting than the fuel in use prior to the

activity or project, including, but not limited to natural gas or coal re-burning, or coal reburning, or the co-firing of natural gas and other fuels for the purpose of controlling emissions; (iii) A permanent clean coal technology demonstration project conducted under Title II, Section 101(d) of the Further Continuing Appropriations Act of 1985 (sec 5903(d) of Title 42 of the Unites States Code), or subsequent appropriations, up to a total amount of $2,500,000,000 for commercial demonstration of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency; or (iv) A permanent clean coal technology demonstration project that constitutes a repowering project.

12. The 1977 amendments to the Clean Air Act (Public Law 95-95) gave the National Park Service and U.S. Forest Service an affirmative responsibility to protect air quality related values (including visibility) within Class I areas. The 1990 amendments to the Clean Air Act (Public Law 101-549) reaffirmed this responsibility.

13. The Wilderness Act (Public Law 88-157) gave the U.S. Forest Service and National Park Service the responsibility of managing designated wildernesses to preserve and protect their wilderness character. Pursuant to this law, the regulations for managing wilderness and primitive areas require that national forest wilderness resources be managed to promote, perpetuate, and where necessary, restore the wilderness character of the land. In western Washington, much of Mount Rainier, North Cascades and Olympic National Parks were designated as wilderness by Public Law 100-668, the Washington Park Wilderness Act of 1988.

14. The National Forest Management Act (Public Law 94-588) gave the U.S. Forest Service the authority to determine the management goals and objectives for wilderness areas. In the Pacific Northwest, the Forest Service (Region 6) established the following management principles for air quality in wilderness areas:

a. All components of the wilderness resource are equally important.

b. All trophic levels are equally important; that is, micro-organisms are as important as elk and grizzly bears.

c. Even the most sensitive components are to be protected, not just those of "average" or "normal" sensitivity.

d. Wilderness components are to be protected from human-caused change, not just damage (Ref. 13).

15. The National Acid Precipitation Act of 1980 confirmed that acid deposition was an important enough issue to receive separate action by Congress.

16. Washington State and the Pacific Northwest contain a significant number of Class I wilderness areas and National Parks (Ref. 3). They include:

a. Class I wilderness areas in Washington - Mount Adams, Goat Rocks, Alpine Lakes, Glacier Peak and Pasayten.

b. National Parks in Washington - Mount Rainier National Park, North Cascades National Park and Olympic National Park.

c. Class I wilderness areas and National Parks in Oregon - Mount Hood, Mount Jefferson, Mount Washington, Three Sisters, Diamond Peak, Gearhart Mountain, Mountain Lakes, Strawberry Mountain, Eagle Cap, Kalmiopsis, Hells Canyon and Crater Lake.

17. Mount Rainier National Park was established as the nation's fifth national park in 1899. Its enabling legislation reads that the park shall receive: "...preservation from injury or spoilation of all timber, mineral deposits, natural curiosities or wonders within said park and retention in their natural condition..." The Organic Act of 1916 (P.L. Chapter 408, 39Stat.535 et seq., 16 USC 1) and the Redwoods Act (P.L. 95-250, 92Stat.163, as amended, 1978) are also relevant statutes (Ref. 4).

18. The National Park Service and U.S. Forest Service have the authority to make recommendations to air quality agencies on the impacts of new or proposed power plants and recommend mitigation measures necessary to protect the wilderness areas and national parks. Air quality agencies may reject these recommendations only after stating the rationale for such a decision (Ref. 13 and Section 169A Clean Air Act).

19. The procedure utilized in a RACT determination includes, for the most part, the following (Ref. 5):

a.All control technologies which are available and applicable for the source are to be considered.

b.The control technology that will result in the lowest level of emission is to be evaluated first. To ascertain which controls will result in the lowest emissions, all must be evaluated.

c.The amount of reduction in emissions that the selected technology will achieve must be determined. Existing emissions and controls must be considered as the basis for the calculation.

d.A determination must be made that the calculated emission reductions will improve air quality or provide other environmental benefits. Washington courts have held that significant emissions reductions are considered to be improvements in air quality.

e.A determination needs to be made that if the annualized cost of additional controls including all life-cycle costs necessary to install, implement, maintain and operate RACT at the source over the life of the installation is reasonable, then RACT is defined for the source. If it is not, the process is repeated using the control technology which will achieve the next highest level of emissions reduction until RACT is defined. Setting the actual emission limit for this source may necessitate consideration of such issues as operational flexibility.

20. A RACT conclusion is a policy judgment which is made after weighing the environmental impacts of the source against the costs of achieving a particular emissions reduction (Ref. 7, Appendix A, p. 30).

21. RACT determinations are expected to address, where practicable, air contaminants deemed to be of concern for the source (Ref. 1, RCW 70.94.154(5)).

22. In the 9th Circuit Court re: Central Arizona Water Conservation District, No. 91-70731, IV.1.a, "...EPA chose not to adopt the emission control limits indicated by BART analysis, but instead to adopt an emission limitations standard that would produce greater visibility improvement at a lower cost. Congress's use of the term `including' in ' 7491(b)(2) prior to its listing BART as a method of attaining `reasonable progress' supports EPA's position that it has the discretion to adopt implementation plan provisions other than those provided by BART analyses in situations where the agency reasonably concludes that more `reasonable progress' will thereby be attained" (Ref. 62).

23. Section 169A of the 1977 Federal Clean Air Act required the Administrator of EPA to complete a study and report to Congress on available methods for implementing the national goal of the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution. In addition, EPA was to promulgate regulations to assure reasonable progress in achieving the national goal. Such rules were to provide guidelines to the States and require each affected state to revise the State Implementation Plan to include provisions to make reasonable progress. The Act required that sources contributing to visibility impairment install Best Available Retrofit Technology (BART). BART for fossil-fuel fired power plants with a generating capacity in excess of 750 megawatts must be determined pursuant to EPA guidelines. EPA developed guidelines pursuant to this requirement which are identified in the EPA document titled Guidelines for Determining Best Available Retrofit Technology for Coal-Fired Power Plants and Other Stationary Facilities (EPA-450/3-80-009b) (November 1980) (Ref. 33). In accordance with Section 169A, the EPA promulgated visibility regulations on December 2, 1980 at 40 CFR 51.300 et seq. (Subpart P). All mandatory Class I areas where visibility is an important value were identified in the November 30, 1979, Federal Register (44 FR 69122).

24. Centralia Plant was constructed in 1971 and 1972, prior to the promulgation of 40 CFR 60.40 et seq. (Subpart D) and 40 CFR 60.40a et seq. (Subpart Da), and therefore are not applicable to the Centralia Plant. Notwithstanding, 40 CFR 60.40 et seq. (Subpart D) Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971 provides standards for oxides of nitrogen, particulate matter and sulfur dioxide emissions for applicable units. The original regulation was promulgated on December 23, 1971 for large fossil-fuel-fired steam generating units constructed after August 17, 1971 and has subsequently been revised numerous times. The original standard for sulfur dioxide was 1.2 pounds per million Btu (lb/MBtu) heat input (no averaging time specified). Emissions of nitrogen oxides was limited to 0.70 lb/MBtu heat input (no averaging time specified). Changes in 1979 added Subpart Da for units constructed after September 18, 1978. Changes in 1983 established sulfur dioxide compliance, emission monitoring, and reporting requirements on a 30-day rolling average basis. Shorter averaging times were identified in rule making to severely limit compliance coal supplies for plants subject to the standard and could lead to the use of costly coal blending facilities. As currently promulgated pertinent limits include 99% reduction of particulate matter, not to exceed 20% opacity (6-minute average), not to exceed 1.2 lb/MBtu (30 day average) and 10% of the combustion concentration (90 percent reduction) for sulfur dioxide or 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 0.60 lb/million Btu heat input, and for subbituminous coal, not to exceed 0.50 lb/million Btu and achieve 65% reduction for emissions of nitrogen oxides.

25. For purposes of a BART comparison for Centralia Plant, the emission limits to be met if 40 CFR 60.40a et seq. were applicable, would include the following:

' 60.42a Standard for particulate matter.

(a) ...no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of:

(1) 0.03 lb/million Btu heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

...no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

'60.43a Standard for sulfur dioxide.

(a) ...no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel any gases which contain sulfur dioxide in excess of:...

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 0.60 lb/million Btu heat input.

'60.44a Standard for nitrogen oxides.

(a) ...no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides in excess of the following emission limits, based on a 30-day rolling average.

(1) NO_x emission limits.

Fuel type: Subbituminous coal - Emission limit for heat input = 0.50 lb/million Btu

(2) NO_x reduction requirement.

Fuel type: Solid fuels - Reduction of potential combustion concentration = 65%

'60.46a Compliance provisions.

(e) After the initial performance test required '60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under '60.43a and the nitrogen oxides emission limitations under '60.44a is based on the average emission rate for 30 successive boiler operating days.

26. Section 169B of the Federal Clean Air Act provides for EPA and other federal land managers to conduct research and identify and evaluate sources and source regions of both visibility impairment and regions that provide predominantly clean air in Class I areas. Internal procedures for determining adverse impacts were developed by the Department of the Interior and published in the Federal Register (47 FR 30226) (Volume 47, No. 133 / Monday, July 12, 1982). Such procedures provide for review of new source permits which have an increase in emissions. A determination of "adverse impact" or "no adverse impact" is to be published in the Federal Register.

27. "The states must determine emission limitations for fossil fuel-fired power plants with a total generating capacity in excess of 750 megawatts pursuant to this guideline, which reflects EPA's conclusion that the controls needed to meet the new source performance standards (NSPS) for power plants (40 CFR 60, Subpart Da) are generally available to these sources" (Ref. 3, p. 1).

28. In a letter dated November 14, 1985 the National Park Service (NPS) notified the US EPA of visibility impairment in all national parks: "It is the position of the NPS that all NPS class I and class II areas in the lower 48 states are being affected by this visibility degrading uniform haze." Neither Mount Rainier nor the other national parks or wildernesses within Washington State were specifically identified as having suspected attributable point sources of visibility impairment at that time.

29. In a letter dated October 16, 1995, from the National Park Service (NPS) to the Washington Department of Ecology (WDOE), the NPS cited several studies to demonstrate that the Centralia Plant's emissions contribute to visibility impairment and acid deposition at one or more Class I national park and wilderness areas in Washington. WDOE was requested to review and, if appropriate, confirm the finding of reasonable attribution with respect to the Centralia Plant. One possible option for resolution cited in the letter was to "explore whether the parties can agree on control strategies that would result in additional SO_2 reductions beyond RACT, in settlement of all the concerns raised about the Centralia Power Plant's emissions." (Ref. 63).

30. The objectives of the PREVENT study (1994) were: (1) to determine the spatial and temporal patterns of aerosol concentration, chemical composition, and particle size; regional emissions; and light extinction and observed visual effects; (2) to determine estimates of the light extinction budgets for the summer period for Mount Rainier and North Cascades National Parks; (3) to apportion (or attribute) the summertime haze observed in Federal Class I areas in Washington to the regional emissions from all sources in the Pacific Northwest and British Columbia; and (4) to determine the contributions from natural and man-made sources. (Ref. 21, p. 1-2)

31. In a letter dated March 9, 1995, the Centralia Plant provided the following points with regard to the PREVENT study:

a. The role of sulfate in light extinction may be substantially less than previously thought. Recent work completed as part of project MOHAVE near Grand Canyon National Park suggests that elemental carbon occupies a much larger part of the extinct budget than previously thought. The work of Malm and others suggest that there are significant quantities of carbon in the atmosphere in the Northwest (Ref. 24, p. 12).

b. Total light extinction was never actually measured during the PREVENT study. Since the extinction coefficient is an estimate, any contribution made to it must also be considered an estimate and subject to further measurement and analysis (Ref. 24, p. 14).

c. The largest contributor to visibility reduction can not be determined if the total visibility reduction or extinction was not measured during the PREVENT study. No emissions inventory, no stack or area source sampling was ever attempted during PREVENT. The contribution of sulfur to visibility reduction is based purely on statistical extrapolation of the data and may not be correct (Ref. 24, p. 14).

d. The very nature of the "hits" appear to be somewhat of conjecture and their ultimate impact on visibility reduction is not discussed (Ref. 24, p. 14).

e. The PREVENT study was not able to establish a strong relationship between selenium and Centralia Plant's emissions (Ref. 24, p. 15).

f. The PREVENT report's conclusions attributing visibility impairment to Centralia Plant emissions are based on supposition. The Respondent further believes that more study, additional monitoring and analysis are necessary to determine if reduction of Centralia Plant's emissions will result in a perceptible improvement of visibility in the region's Class 1 areas (Ref. 24, p. 17).

32. SWAPCA 400-030(2) defines adverse impact on visibility as "visibility impairment which interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of a Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility

impairments, and how these factors correlate with (a) times of visitor use of the Federal Class I area, and (b) the frequency and timing of natural conditions that reduce visibility. This term does not include effects on integral vistas."

33. SWAPCA 400-030(9) defines Best Available Retrofit Technology (BART) as "an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under Chapter 70.94 RCW which would be emitted from or which results from any new or modified stationary source, which the Authority, on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs, determines is achievable for such source or modification through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment, clean fuels, or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of the "best available control technology" result in emissions of any air pollutants which will exceed the emissions allowed by any applicable standard under 40 CFR Part 60, Part 61, and Part 63 as they exist on August 1, 1996, or their later enactments as adopted by reference by the Authority by rule. Emissions from any source utilizing clean fuels, or any other means, to comply with this paragraph shall not be allowed to increase above levels that would have been required under the definition of BACT in the Federal Clean Air Act as it existed prior to enactment of the Clean Air Act Amendments of 1990."

34. SWAPCA 400-030(43) defines integral vista as "a view perceived from within a mandatory Class I Federal area of a specific landmark or panorama located outside the boundary of the mandatory Class I Federal Area."

35. As provided in SWAPCA 400-151 and WAC 173-400-151, SWAPCA or Ecology shall:

(1)identify and analyze each source which may reasonably be anticipated to cause or contribute to impairment of visibility in any mandatory Class area in Washington and any adjacent state and to determine BART for the contaminant of concern and those additional air pollution control technologies that are to be required to reduce impairment from the source.

(2)the owner or operator of any source to which significant visibility impairment of a mandatory Class I area is reasonably attributable shall apply BART for each contaminant contributing to visibility impairment that is emitted at more than 250 tons per year.

36. In meetings between EPA and other parties in the Navajo issue, the meetings resulted in a "memorandum of understanding" which recommended that EPA adopt a regulatory approach designed to achieve a greater degree of visibility improvement in the Grand Canyon at lower cost than the proposal published by EPA in February 1991. EPA determined that this approach would more adequately achieve "reasonable progress" toward the national visibility goal under section 169A(b)(2) of the Act, than would the alternative provided by BART analysis (Ref. 62).

37. The Centralia Plant Collaborative Decision Making (CDM) group agreed to a target solution that results in substantially lower actual and permitted SO_2 values than what were originally proposed under the original RACT Order (SWAPCA 95-1787). This agreed Centralia solution has been determined by SWAPCA, after consultation with the Federal Land Managers, EPA, and WDOE, to represent what might otherwise be established by a BART determination based on the substantial emission reductions and limits proposed through the negotiated process.

38. In a paper titled "Collaborative Decision Making To Reduce Impacts of the Centralia Power Plant on Air Quality Related Values," prepared by Janice Peterson of the USDA Forest Service, several points were made that summarized the CDM process and outcome (Ref. 66):

a. The Forest Service supports the contention of the group that the voluntary process reached a better solution than could have been reached through a costly, time consuming, and adversarial court battle as could have occurred if a formal BART analysis process was used instead.

b. In general, the opinion of the Forest Service (and other participants in the Washington RACT process) was that a BART proceeding was not necessarily the preferred approach to meeting our goals.

c. The group worked primarily with 8 potential target solutions which spanned the range from plant and mine closure, to mine closure with substitution of cleaner coal, to 70 percent scrubbing with various phase-in schedules. A 90 percent scrubbing solution did not surface as an option until further cost savings could be identified that would allow the owners to implement such an option while remaining financially viable.

d. Previous examples of "dueling science" have sometimes proved little beyond how wide the range of uncertainty in scientific results can be and how difficult it is to quantify and characterize air pollution effects. The participants agreed simply that there would be a benefit to regional air quality and air quality related values from controlling SO_2 emissions from the Centralia Plant.

e. The Collaborative Decision Making group, through months of difficult negotiations, reached a control solution for SO_2 emissions from the Centralia Plant that both protects the environment and protects the jobs of the people that work at the mine and plant. The Forest Service believes this solution to be as good or better than what could have been achieved through a regulatory process.

39. Neither visual range nor extinction coefficient is linear with humanly perceived changes caused by uniform haze. A given change in visual range or extinction coefficient can result in a scene change that is unnoticeably small or very apparent depending on the baseline visibility conditions (Ref. 68, p. 1-7).

40. In a letter dated August 11, 1997 from PacifiCorp to SWAPCA, the Centralia Plant requested that SWAPCA determine that the emission limits to be set by the RACT proceedings for the Centralia Plant also meet "Best Available Retrofit Technology" (BART) emission limits. Additional information relative to the Navajo Generating Station and Hayden Station settlements regarding visibility issues were provided as the basis for the request. (Ref. 69)

41. In a letter dated August 29, 1997 from the National Park Service to SWAPCA, the NPS stated that: "The NPS also believes that the proposed CDM Target Solution including the proposed scrubber and emission limitations, meet or exceed the emission control requirements of BART." (Ref. 70).

42. In a letter dated September 3, 1997 from the USDA Forest Service to SWAPCA, the Forest Service indicated that: "After considering all the information at hand, we believe that it is in the best interest of the environment, the public, and all parties to the CDM process, that a BART review be accomplished and documented as PacifiCorp has requested... Much of the information needed to accomplish this review already exists within the CDM archive, the PREVENT documentation, the NPS modeling study (Vimont), the documents released to the public at the

CDM public meetings, analysis that Washington DOE has accomplished, etc... In our view, the CDM agreement is as good or better than BART, although it may not be identical to BART" (Ref. 71).

43. In a letter dated September 3, 1997 from EPA Region 10 to SWAPCA, EPA indicated that: "EPA recognizes that no BART proceedings have been completed to date. However, the CDM process has resulted in a proposed regulatory approach for the Centralia Plant that we anticipate will constitute BART. BART controls are determined on a case-by-case basis and are based on an assessment of: improvements in visibility, an engineering analysis, as well as energy, environmental, and economic impacts, the documents and records compiled for the CDM process, including the alternatives considered, will provide a strong foundation for completing the BART analysis. After that analysis is completed, the level of control constituting BART will be established" (Ref. 72).

44. In a letter dated September 15, 1997 from PacifiCorp to SWAPCA, the Centralia Plant requested a voluntary limit on the annual throughput of fuel combusted in the auxiliary boiler, reiterated that CO should not be considered a pollutant of concern, proposed emissions language agreed by the CDM group regarding use of the existing stacks for emergency bypass in the event of new stack(s) being constructed, proposed a compliance schedule in the event that a RACT Order is not finalized in a timely measure and provided interim milestones to ensure progress toward implementation of the CDM and RACT emission limits. (Ref. 73)

1.3 Regulatory Conclusions

This section provides conclusions based on the preceding regulatory references and consideration of results from the collaborative decision making process.

1. The Centralia Plant was constructed in 1971 and 1972 prior to promulgation of the PSD rules, therefore, no PSD permit was required at the time of construction.

2. Installation of the second set of electrostatic precipitators (Lodge-Cottrell) to the Centralia Plant in 1974 did not constitute a major modification because the original ESPs (Koppers) did not meet original performance specifications and they would have been considered to be a pollution control project.

3. Other than the installation of the second set of ESPs, there have been no major modifications at the Centralia Plant which would have triggered a PSD review.

4. Construction on the Centralia Plant was commenced in about 1968 and it became operational in 1971 and 1972 prior to promulgation of the NSPS for fossil-fuel-fired boilers (40 CFR 60.40 et seq. (Subpart D and Da), therefore, compliance with the NSPS provisions was not required at the time of construction.

5. Modifications to be made at the Centralia Plant that are required to meet Washington State requirements to have reasonably available control technology for the facility are considered a pollution control project.

6. Installation of pollution control equipment (as a pollution control project) does not constitute a major modification at a major stationary source, therefore, no PSD permit is required for installation of additional equipment. Any modification made to the Centralia Plant as a result of this Order is considered to be a pollution control project and therefore will not trigger PSD.

7. The RACT/BACT/LAER Clearinghouse information identifying technology determinations for similar units is appropriate to use, even though the number of RACT determinations is minimal. The BACT and PSD documentation is applicable to coal fired power plants for the purpose of identifying available control technology, however, the cost effectiveness of a technology for RACT consideration may be substantially less that a determination for BACT or PSD purposes. SWAPCA considered this information as a guideline to determine types and availability of control equipment. The cost effectiveness and emission reductions to be achieved by any particular technology is determined on a case-by-case basis for the Centralia Plant.

8. The Centralia Plant is not a new or modified source under this RACT review. The provisions of 40 CFR 52 (PSD) are not triggered and thus a permit review under that section is not required.

9. Depending on the technology selected to meet the SO_2 and NO_x emission limit, CO emissions are likely to increase above PSD significance levels. This increase has been determined to not cause an exceedence of the CO National Ambient Air Quality Standard (NAAQS) and does not represent a significant degradation of air quality. The likely increase in CO emissions is environmentally offset by more significant reductions in SO_2 and NO_x which have greater impact to

the environment because of the quantity of emissions, acid rain impact, visibility issues and potential health impacts from each pollutant.

10. The Centralia Plant is not considered to be a new source or modified source in accordance with federal, state and local PSD and new source review provisions. Therefore, because there is no increase in pollutants that would contribute to visibility impairment (actually a large decrease) there is no adverse impact on visibility that needs to be considered. However, because the current RACT Order requires a large decrease in emissions that presently may be contributing to visibility degradation, one may draw a reasonable conclusion that visibility improvement may occur in nearby Class I and Class II areas.

11. BART has not been triggered because there has not been an explicit declaration by the state that there is visibility impairment in the Class I areas and neither SWAPCA nor WDOE has performed a reasonable attribution study or BART analysis.

12. In a letter dated August 11, 1997, the Centralia Plant requested that SWAPCA proceed with a determination that the proposed emission controls for Centralia Plant meet or exceed BART requirements. The Collaborative Decision Making process agreed upon substantially lower emission levels that meet or exceed levels that might otherwise be determined under BART if reasonable attribution had been made.

13. SWAPCA concludes that, after installation of control equipment satisfying RACT/CDM emission limits, Centralia Plant's emissions are not expected to contribute significantly to visibility impairment in Mount Rainier National Park and other Class I areas in Washington.

14. SWAPCA concludes that after consultation with the Federal Land Managers, the EPA, and the Washington Department of Ecology and a review of the BART criteria, the emission limits and control strategies identified for the Centralia Plant have been deemed to meet or exceed limitations that might have otherwise been required under a more time consuming and expensive BART regulatory process. As a result, the Centralia Plant shall not be subject to a similar visibility evaluation in the future for the same pollutants as provided in 40 CFR 51.302(c)(4)(v)(B).

15. The emission limits established by the CDM process meet or exceed limits established by RACT and that, based on the percent reduction achieved by the CDM process, the RACT limits established meet or exceed the limits and percent reduction requirements of the applicable NSPS for a new facility. The difference between the NSPS limits and the CDM Target Solution is the time period over which emissions are to be averaged for compliance demonstration purposes. The NSPS standard for SO_2 is a higher value but is based on a 30 day rolling average while the RACT/CDM limit is a lower value but has an annual averaging period. In addition, a typical SO_2 scrubber installation provides multiple scrubber vessels sometimes with excess capacity to enable a vessel to be taken off-line when necessary for maintenance. In order for the scrubber option to be cost effective at Centralia Plant, the CDM group agreed to only one scrubber vessel of maximum capacity per unit. In order to achieve substantial SO_2 reductions cost effectively, additional operational flexibility was provided to the Centralia Plant to allow the plant to continue operating for a short time period when necessary to perform short-term maintenance on the scrubber vessel. Under this scenario, the scrubber vessel for an individual unit may be bypassed for a short period of time. In addition, the percent reduction and emission limits established by the CDM process for the

Centralia Plant are substantially equivalent to limits that have been established for new similar plants, based upon an inspection of data provided in the RACT/BACT/LAER Clearinghouse.

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Section 2.0

DETERMINATION OF EMISSION UNITS AND POLLUTANTS OF CONCERN

This section is focused on emission units and pollutants for which RACT should be evaluated. This section is provided as a screening section to establish a basis for those emission units and pollutants for which a detailed analysis will be performed and establish a basis why other emission units and pollutants will not be further evaluated. This section is divided into four subsections: (1) Regulatory Basis, (2) Determination of Emission Units Considered for RACT, (3) Determination of Pollutants of Concern Considered for RACT, and (4) Emission Units and Pollutants Conclusions. Section 1 provides regulatory citations and legal proceedings that were used to help provide insight on how to establish which emission units and which pollutants should be considered for RACT evaluation. Section 2 identifies the individual emission units at the Centralia Plant. This includes significant and insignificant emission units. Section 3 identifies pollutants that are both regulated and unregulated. These pollutants have been identified by different organizations that have provided early input into this process to ensure that appropriate consideration is provided for all potential pollutants of concern. Section 4 provides summary conclusions for the emission units and pollutants of concern for RACT evaluation. Each pollutant is evaluated based on its own contribution and potential impacts and in combination with other pollutants, when appropriate.

2.1 Regulatory Basis

1. Section 108(a)(1) of the Federal Clean Air Act requires the EPA to establish national primary and secondary ambient air quality standards, and to publish and maintain a list of air pollutants (A) emissions of which cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare; (B) the presence of which in the ambient air results from numerous or diverse mobile or stationary sources; and (C) for which air quality criteria had not been issued before the date of enactment of the Clean Air Act Amendments of 1970, but for which the Administrator plans to issue air quality criteria under this section. Pollutants identified under this section are referred to as criteria pollutants.

2. Section 112(b) of the 1990 Federal Clean Air Act amendments contains a list of hazardous air pollutants established by Congress under the Act. The EPA was required to periodically review and update the list. No pollutant listed under Section 108(a) may be added to the list except that the prohibition shall not apply to any pollutant which independently meets the listing criteria and is a precursor to a pollutant which is listed under Section 108(a).

3. Section 112(n) of the Federal Clean Air Act requires the EPA to perform a study of the hazards to the public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units of pollutants listed under Section 112(b). In addition, the EPA was required to conduct and transmit to Congress a study of mercury emissions from electric utility steam generating units. The study was to consider the rate and mass of emissions, the health and environmental effects of such emissions, technologies which are available to control such emissions, and the costs of such technologies. In addition, the National Institute of Environmental Health Sciences was required to conduct and transmit to Congress a study to determine the threshold level of mercury exposure below which adverse human health effects are not expected to occur.

4. RCW 70.94.154(5) states that: "In establishing or revising RACT requirements, ecology and local authorities shall address, where practicable, all air contaminants deemed to be of concern for that source or source category".

5. SWAPCA 400-030(3) defines "air contaminant" as meaning dust, fumes, mist, smoke, other particulate matter, vapor, gas, odorous substance, or any combination thereof. This includes any substance regulated as an air pollutant under SWAPCA 460, NESHAPS, Section 112 of the federal Clean Air Act Amendments or substance for which a primary or secondary National Ambient Air Quality Standard has been established and volatile organic compounds. "Air pollutant" means the same as "air contaminant". (Also RCW 70.94.030(1) and WAC 173-400-030(3))

6. SWAPCA 400-030(4) defines "air pollution" as meaning the presence in the outdoor atmosphere of one or more air contaminants in sufficient quantities, and of such characteristics and duration as is, or is likely to be, injurious to human health, plant or animal life, or property, or which unreasonably interferes with enjoyment of life and property. For the purposes of this regulation air pollution shall not include air contaminants emitted in compliance with Chapter 17.21 RCW, the Washington Pesticide Application Act, which regulates the application and control of various pesticides. (Also RCW 70.94.030(2) and WAC 173-400-030(4))

7. SWAPCA 400-030(28) defines "emissions unit" as any part of a stationary source which emits or would have the potential to emit any pollutant subject to regulation under the FCAA, Chapter 70.94 RCW or Chapter 70.98 RCW.

8. SWAPCA 400-101 "Sources Exempt from Registration Requirements" identifies sources or source categories which are exempt from registration and new source review based on insignificant emissions of less than 1.0 ton per year for criteria pollutants or the small quantity emission rate of WAC 173-460 for each toxic pollutant, which does not result in the 1.0 tpy criteria to be exceeded.

9. WAC 173-401 "Operating Permit Regulation" Section 530 "Insignificant Emission Units" contains criteria for identifying insignificant emission units or activities for the purposes of obtaining a Title 5 permit.

10. WAC 173-401 "Operating Permit Regulation" Section 531 "Thresholds for Hazardous Air Pollutants" contains criteria for identifying insignificant emission units or activities which emit hazardous air pollutants for the purposes of obtaining a Title 5 permit.

11. WAC 173-401 "Operating Permit Regulation" Section 532 "Categorically Exempt Insignificant Emission Units" contains lists of units or activities that are categorically insignificant emission units or activities and exempt from permitting for the purposes of obtaining a Title 5 permit.

12. WAC 173-401 "Operating Permit Regulation" Section 533 "Units and Activities Defined as Insignificant on the Basis of Size or Production Rate" contains lists of units or activities that are considered insignificant based on size or production rate and are exempt from permitting for the purposes of obtaining a Title 5 permit.

13. Significant impacts to air quality are cause for a pollutant to be of concern and therefore subject to a RACT determination. However, lacking significant impact relative to the ambient air quality

standard, other air quality factors, including but not limited to, nuisance, odor, fallout, or health impacts could be a basis for requiring a RACT determination (Ref. 36).

14. Potential to Emit for particulate matter is established, based on definition (SWAPCA 400-030(70)), as the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restriction on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is federally enforceable. For Centralia Plant, the limiting factor for particulate matter is 0.06 gr/dscf which is based on the original SWAPCA approval to construct the Centralia Plant, guarantees from the ESP manufacturer, and subsequent SWAPCA approvals. Therefore, the maximum potential to emit is calculated as 60 minutes per hour, times 8760 hours per year, times the maximum emission concentration of 0.06 gr/dscf, times the maximum design exhaust gas flow rate of 1,523,567 dscf/min, divided by 7000 grains per pound, divided by 2000 lb per ton which equals approximately 3432 tons per year per unit (6864 tons per year both units).

15. Final guidance is not yet available within Washington State describing the specific approach to conducting a RACT evaluation for existing sources within Washington. Therefore, for reference, SWAPCA consulted the available RACT guidance documents, including the Department of Ecology's Draft Source-Specific RACT Guidelines, dated June 20, 1997; EPA's Procedures for Identifying Reasonably Available control Technology For Stationary Sources of PM-10, dated September 1992 (EPA-452/R-93-001); 40 CFR Part 52, General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990 (57 Fed.Reg. 13498); and other states' RACT guidance documents. For comparison, SWAPCA also referred to the New Source Review Workshop Manual (Ref. 61) and various BACT and PSD determinations.

16. Because "pollutants of concern" is not explicitly defined, SWAPCA identified several citations to other regulations to establish what levels of pollutants might be reasonable to use as a measure of what might be considered to be significant and therefore "of concern". This determination is made on a case-by-case basis considering unique aspects of the emissions unit and pollutants involved. These examples include levels that can be exempted from monitoring requirements under the federal PSD program as found at 40 CFR 52.21(i), NSPS standards of 40 CFR 60, SWAPCA 400, WAC 173-400, SWAPCA 490, WAC 173-490, WAC 173-401, and WAC 173-460.

2.2 Determination of Emission Units Considered for RACT

Emission units have been identified for the Centralia Plant in the RACT submittal Appendix A, in the SWAPCA 1996 Emission Inventory data sheets, and the Title 5 Permit Application as the following:

Emission Unit No.	Emission Unit Description
01	Boiler #1
02	Boiler #2
03	Auxiliary Boiler
50	Interim Coal Storage Conveyors
51	Coal Storage Piles
55	Welding Emissions from Maintenance Operations
56	Coal Silos 1 & 2
57	Cooling Towers 1 & 2

Additional emission units identified as insignificant emission units (IEUs) were included in the Centralia Plant Title 5 application submitted to SWAPCA in June 1995. Supplemental information in the application on Page A-50 identified the following four additional emission units:

Emission Unit No.	Emission Unit Description
1	Unit #1 and #2 Turbine Lube Oil System Vapor Extractors / Oil Mist Eliminators
2	Parts Washing Solvent Tanks
3	Unit #1 and #2 Emergency Diesel Generators
4	Underground Gasoline Storage Tanks

Emission units 01 and 02 (Boilers #1 and #2) are considered to be emission units subject to RACT evaluation because they are the major emitting units at the facility. Each of these emission units emits a substantial quantity of criteria and hazardous/toxic air pollutants. Attachment A of the RACT Submittal, Appendix A, (Ref. 29) included a list of pollutants emitted from the Centralia Plant as documented on SWAPCA 1996 Emission Inventory Data Sheets. Pollutants and annual emissions were summarized on the emission inventory as follows for Boilers #1 and #2 combined:

Sulfur oxides - 78,272 tpy
Particulate matter - 3428 tpy
Particulate matter (<10Φm) - 3428 tpy
Oxides of nitrogen - 18,565 tpy
Volatile organic compounds - 164.4 tpy
Carbon monoxide - 1371 tpy
Toxic/Hazardous air pollutants - 143.8 tpy
Carbon dioxide - 8.9 million tpy (estimated)

Neither of these units have contributed to known violations of the ambient air quality standards, however, due to the nature and substantial quantity of their emissions they could be a contributor to other environmental impacts including visibility degradation. Because of the large amount of emissions, the availability of control equipment and the relative cost effectiveness of available control equipment, these emission units should be evaluated for RACT.

Emission unit 03 (auxiliary boiler) is the largest emission unit apart from the main boilers at the Centralia Plant. The auxiliary boiler is manufactured by Babcock & Wilcox and is rated at 115,000 lb/hr of steam (~170 million Btu/hr). Actual emissions are calculated based on the quantity of fuel burned in a calendar year. Fuel consumption in gallons for 1993, 1994, 1995 and 1996 were approximately 171,000, 44,000, 217,000, and 78,000, respectively. Emission factors from AP-42 were used to estimate emissions. The fuel combusted in the auxiliary boiler is #2 distillate fuel (#2 fuel oil, average heating value of ~141,000 Btu/gal). Design data submitted with the 1996 emission inventory included the design capacity of the auxiliary boiler which is stated to consume up to 1200 gallons per hour of fuel oil. Hours of operation were identified as 68 hours per year for 1996. Potential to emit for this boiler is based on 8760 hours per year and 1200 gallons per hour. Utilizing AP-42 emission factors from the emission inventory submittal, this equates to 10.5 tpy TSP, 373.2 tpy SO_2 (0.5%S), 105.1 tpy NO_x, 1.05 tpy VOC, 26.3 tpy CO and 172.0 lb/yr HAP. Stack height is 250 feet above ground level. Actual emissions based on 78,000 gallons of fuel combusted was reported in the 1996 Emission Inventory as 0.08 tpy TSP, 0.08 tpy PM, 0.28 tpy SO_2 (0.05%S), 0.78 tpy NO_x, 0.01 tpy VOC, 0.20 tpy CO, and 1.28 lb/yr HAPs. Because there is no applicable limit for this unit other than the 0.1 gr/dscf for particulate matter and 1000 ppm for SO_2, the potential to emit (PTE) for this emission unit alone would make the Centralia Plant a Title 5 source (major). In a letter dated September 15, 1997, the Centralia Plant requested to take a voluntary limit on the amount of fuel to be combusted in the auxiliary boiler on an annual basis. Because this unit is used on a minimal basis, as supported by previous emission reports, the Centralia Plant has requested an annual limit of diesel consumption for the auxiliary boiler only of 600,000 gallons. Based on this limitation, PTE for this emission unit would be:

Pollutant	AP-42 Factor (lb/1000 gal)	Potential to emit (tons/yr)
SO_2*	142S	4.26
NO_x	20.0	6.0
CO	5.0	1.5
PM_{total}	2.0	0.60
VOC	0.252	0.075

* sulfur content is assumed to not exceed 0.10% by weight

Based on the voluntary request for fuel combustion limitation, the potential to emit of the emission unit, the type and quantity of emissions each year, and the potential impact of emissions from the auxiliary boiler, this emission unit should not be considered for further RACT evaluation.

Emission units 50 and 51 (coal storage conveyors and coal piles) are not consider to be emission units subject to RACT at this time due to inherent design limitations, potential to emit from the units, availability of additional controls, and current emissions. As indicated in the 1996 Emission Inventory, the only pollutant emitted by these emission units is particulate matter (TSP and PM_{10}). Combined emissions from these emission units are less than 1.0 tpy. The coal is washed and wetted during cleaning and processing. Generally the coal does not remain in a pile for more than a few days under normal operation. Therefore, because the coal is wet and not allowed to dry substantially and the fact that many of the conveyors are covered there is little potential for fugitive emissions. No additional controls are available to further minimize emissions, the amount of emissions discharged to the ambient air are insignificant, and those emissions have no identifiable impact on public health or the environment. There would be no benefit to be gained from performing further in-depth analysis of these emission units. These emission units are not considered for further RACT evaluation.

Emission unit 55 (maintenance activity welding emissions) is a maintenance activity performed at the Centralia Plant that takes place primarily in two shops - the Boiler Shop and the Pulverizer Journal Shop. Welding is not an inherent part of the process of generating electricity as a result of coal combustion. Welding is only performed as necessary to maintain the operational status of equipment. Emissions are directly related to the amount of weld rod consumed at the facility. Based on the 1996 Emission Inventory approximately 180 pounds of particulate matter from welding operations were emitted. Assuming all welding was performed in one of the two shops, these shops have a cartridge filter collector capable of 99.9 % efficiency. This would calculate to approximately 2 pounds per year of emissions. Based on the insignificant amount of emissions from this activity, this emission unit is not considered for further RACT evaluation.

Emission unit 56 (Unit #1 & #2 coal silos) consists of five coal silos that each have an exhaust point to the ambient air. This exhaust point emits small quantities of coal dust (particulate matter) as the result of filling the silos with coal. Each silo has a small cyclone separator that removes much of the coal dust from the exhaust stream. The coal dust evacuation exhausts range in size from 7000 scfm to 8450 scfm and operate 24 hours per day when the generating boilers are in operation. The cyclones have a typical efficiency of approximately 80%. These cyclones are an inherent part of the design of the coal silos. Based on the 1996 Emission Inventory and AP-42 emission factors for these cyclones, total emissions from all five units combined were calculated to be 12.8 tons/yr. Due to the small quantity and the type of emissions from these units, the fact that there is no expected environmental or public health impact attributable to these units, the fact that the emissions are already controlled by about 80%, additional control technologies are not expected to result in substantial reduction in tons per year at a reasonable cost or benefit. Therefore, these units are not considered for further RACT evaluation.

Emission unit 57 (Unit #1 & #2 cooling towers) consists of induced draft wet cooling towers with a circulating water flowrate of approximately 241,000 gallons per minute. This water is circulated between the condenser of the turbine generator and the cooling towers to reduce the temperature of the cooling water supplied to the condenser. Makeup water (raw water) is provided from a surge pond on site. Water in the surge pond is taken from a reservoir on the Skookumchuck River. The water contains small amounts of sediment that may be released upon evaporation of the water in the cooling tower. Circulating water is treated with chlorine and sodium bromide for disinfection, and polymer for dispersion deposit control in the cooling tower fill. Water vapor is emitted from these towers but it is not a pollutant. Emissions of particulate matter as presented in the 1996 Emission Inventory using AP-42 emission factors were calculated to be approximately 26 tpy for both sets of towers combined. Due to the inherent nature of these cooling towers, the small quantity of emissions, the fact that no additional controls could reasonably be provided, the fact that there is no expected environmental or public health impact attributable to these units, these units are not considered for further RACT evaluation.

Insignificant Emission Units identified in the Title V Air Operating Permit Application

Emission Unit 1 - Unit #1 and #2 turbine lube oil system vapor extractors / oil mist eliminators remove water vapor from the turbine lube oil system. Unit #1 and #2 are each provided with an oil storage tank, lube oil reservoir, circulating pump, coolers and oil conditioner. Water vapor becomes entrained in the lube oil system as a result of the seal function performed by the bearings and oil and the close contact the lube oil has with the high pressure steam in the turbine. Water vapor accumulates in the lube oil reservoirs. The purpose of the lube oil system is to provide an adequate supply of clean oil at a suitable temperature and pressure to the turbine-generator bearings, makeup oil to the hydrogen seal oil system, emergency source of oil for the hydrogen seal oil system, and to supply oil to control devices. Water vapor extraction from the lube oil reservoirs is necessary to minimize moisture accumulation in the oil. The oil mist eliminators remove condensible oil mist particles from the water vapor stream prior to discharge to ambient air. The oil mist eliminators are designed to remove 99% of the oil mist from the exhausted water vapor. Emissions from the mist eliminators were estimated in the Title 5 Permit Application (Appendix B) to be approximately 48 pounds per year per unit. Due to the insignificant quantity and the type of emissions from these units, the fact that there is no expected environmental or public health impact attributable to these units, and the fact that the emissions are already controlled by about 99%, additional control technologies are not expected to result in substantial reduction in tons per year at a reasonable cost or benefit. Therefore, these units are not considered for further RACT evaluation.

Emission Unit 2 - Parts washing solvent tanks are used to clean various parts to assist with maintenance activities at the site. There are 8 parts washing solvent tanks located at various locations within the plant. The solvent tanks range in size from 30 gallons to 40 gallons of solvent each. Stoddard solvent is used in each tank. The tanks have lids that are kept closed when not in use. The plant uses a recycling service to maintain the solvent tanks. As noted in the Title 5 Permit Application (Appendix B), approximately 92% of the solvent is recycled. In 1994 approximately 1010 pounds of solvent were used at the plant. Approximately 50% of this is evaporated with the other 50% absorbed in rags and disposed of by other means. This leaves approximately 505 pounds per year of emissions. Due to the insignificant quantity and the type of emissions from these units, the fact that there is no expected environmental or public health impact attributable to these units, and the fact that the emissions are already controlled by recycling, lids on tanks, and other management controls, additional control technologies are not expected to result in substantial reduction in tons per year at a reasonable cost or benefit. Therefore, these units are not considered for further RACT evaluation.

Emission Unit 3 - Unit #1 and #2 emergency diesel generators are used as an emergency backup electrical power source. The two generators are each powered by a 440 hp diesel engine. Each diesel generator is operated for 15 minutes each week to verify proper operation and availability. This amounts to a total of 13 hours per year of test operations. The rate of fuel consumption is 2.6 gallons per hour at full capacity. The diesel engines operate on low sulfur #2 diesel fuel (< 0.05% by wt. sulfur). As provided in SWAPCA 400-101 item 20, internal combustion including diesel engines used for standby emergency power generation which are used less than 100 hours per year and are rated at less than 500 horsepower are exempt from registration and new source review requirements due to the insignificant nature of the emissions. As noted in the 1996 Emission Inventory the emergency diesel generators operate less than 100 hours per year and are rated at less than 500 horsepower, therefore these units are considered insignificant and are not subject to further RACT evaluation.

Emission Unit 4 - Underground gasoline/diesel storage tanks are used at the facility to store gasoline and diesel fuel for plant equipment. One tank of 1000 gallon capacity for unleaded gasoline and one tank of 2000 gallons capacity for low sulfur #2 diesel fuel exist on site. As provided in the 1996 Emission Inventory, approximately 9,700 gallons of unleaded gasoline and 15,000 gallons of #2 diesel fuel were consumed on site. Due to the low volatility of the diesel fuel, emissions from the diesel storage tank are minimal (no emission factor established). Using AP-42 emission factors for gasoline of 21 pounds per 1000 gallons dispensed, emissions of gasoline vapors were about 0.1 tons per year. Due to the insignificant quantity of emissions, these emissions units are not subject to further RACT evaluation.

Conclusion

RACT emission limits are only required to be established for Boilers #1 and #2.

2.3 Determination of Pollutants of Concern Considered for RACT

The purpose of this section is to identify all pollutants which might be considered for purposes of a RACT evaluation and then evaluate each identified pollutant with respect to several factors. These factors are listed below for each pollutant with an evaluation or statement of consideration for each pollutant. A determination of whether each pollutant should be considered for RACT is made on a pollutant-by-pollutant basis, and applies for Units #1 and #2.

2.3.1. SO_2 Considerations

Amount or concentration of pollutant emitted

Emission inventory data and the RACT submittal document (Ref. 29) prepared by the Centralia Plant indicated that SO_2 emissions from the Centralia Plant for calendar years 1990, 1991, 1992, 1993, 1994, 1995 and 1996 were 58,297, 59,450, 69,488, 63,960, 67,435, 52,941 and 78,272 tons per year, respectively, for Boilers #1 and #2, combined. Emissions were based on tons of coal burned and average sulfur concentration in the coal which was derived from CEM SO_2 emissions data. The annual average concentrations ranged from 542 ppm to 667 ppm. In the two most recent years, both stack concentrations and tonnages were higher than in previous years due to both higher sulfur content in the coal and the biases in the Acid Rain CEM data requirements.

Ambient concentration

Sulfur dioxide is not currently monitored in SWAPCA's five county jurisdiction. There are ambient monitors for SO_2 located in Seattle, and areas north of Seattle. There have been only a few exceedences of the SO_2 NAAQS in Washington in recent years as provided below, however, localized exceedences of the Washington SAAQS one hour standard (0.4 ppm) have occurred in Port Angeles, Cosmopolis, Bellingham, and near Bucoda over the past 10 years.

An ambient air monitoring study at several sites was conducted by Washington State University before and after the start-up of Centralia Plant in 1971. Some SO_2 monitoring was conducted before start-up of the plant, and continuous SO_2 measurements were taken from 1972 to 1974 at six sites in the local area, both in the town of Chehalis and in more rural areas. The annual arithmetic mean, or average, SO_2 levels were all below the state ambient SO_2 standard of 0.020 ppm. The highest annual average recorded during this study was 0.017 ppm at the downtown Centralia site (Ref. 29, p. 50).

Ambient air monitoring was conducted from October 1988 through March 1991 at two locations in the proximity of the Centralia Plant. One location was at the Skookumchuck Reservoir and the other at Crawford Mountain. These sites were selected as the most likely to be impacted from Centralia Plant emissions; both sites are located in remote areas northeast of the Centralia Plant. These monitors measured SO_2 concentrations and averaged them over one-hour, 24-hour, and annual time periods. Approximately 99.5% of the hourly SO_2 concentrations were less than 0.05 ppm. An hourly SO_2 value of 0.50 ppm exceeded the 1-hour SAAQS of 0.40 ppm in August 1990, but no other values above the standard were recorded through the end of monitoring in March 1991. Because two 1-hour values above the standard must occur within a one-year period for a violation to occur, neither a violation of, nor compliance with, the standard could be demonstrated since monitoring did not continue for a one-year period after the lone recorded exceedence. Given the location of the monitors, far lower ambient values would be anticipated throughout the remainder of the local area. However, these sites of most likely impact could experience further infrequent high short-term SO_2 concentrations given the trend of higher sulfur coal used at the Centralia Plant. On a monthly and annual basis, neither of the sites measured values that were close to violating the standard.

Violations of an emission limit

At the time of construction of the Centralia Plant the SWAPCA emission standard for SO_2 was 1,500 ppm, no averaging period and no correction for oxygen. This limit was consistently met. In the mid-1970s WDOE revised the WAC to include a 2,000 ppm SO_2 standard for all sources, and added a new limit for all new sources constructed after July 1, 1975 of 1,000 ppm. On December 31, 1976, WDOE again revised the WAC and removed the 2,000 ppm standard, thus requiring all sources to comply with the 1,000 ppm standard (no averaging period). The SWAPCA standard was revised on December 18, 1979 to 1,000 ppm with no averaging period. A 60 minute averaging period was incorporated into the WAC on April 15, 1983 and was adopted by SWAPCA on March 20, 1984. Informal agreements existed between SWAPCA, WDOE and the Centralia Plant to provide for 30 day averaging of the SO_2 emissions. In mid 1986 the coal coming from the mine had increased levels of sulfur and resulted in exceeding the 1,000 ppm limit on a 60 minute average. An Order of Violation was issued by SWAPCA on August 26, 1987 requiring the plant to remedy the SO_2 emissions violations. Over the next several years, variances were received by the Centralia Plant to operate at higher average levels while a solution was found. In a letter dated October 31, 1990 the Centralia Plant notified SWAPCA of an exceedence of the Washington State one-hour ambient standard of 0.4 ppm SO_2 at the Crawford Mountain monitor which occurred on August 12, 1990. In a letter dated February 6, 1991, the Centralia Plant notified SWAPCA that coal sulfur variability was now sufficiently under control to permit the Centralia Plant to comply with the 1000 ppm limit with a 60 minute averaging time. On April 5, 1991, SWAPCA issued Withdrawal of Petition SWAPCA 90-934E which included the enforcement policy regarding the use of continuous emission monitor data for making enforcement judgement decisions for exceedences of the standard. Since this time there have been short term exceedences of the limit but no violations to date.

In a letter dated January 15, 1993, the Centralia Plant notified SWAPCA that on January 5, 1993 there was a 72 minute period in which sulfur dioxide emissions from the Centralia Plant Unit #1 were in excess of 1000 ppm. The exceedence was attributed to the CMC personnel not providing timely notification that the sulfur content in the coal as delivered to the plant was above 1%. By the time the notification was made to the Centralia Plant personnel, a substantial amount of higher sulfur coal had been sent to the coal silos. The only way to remove the coal from the silos is to burn through it. Unit #2 did not experience an exceedence because at the time of the silo loading, Unit #2 silos were near full and did not receive an appreciable amount of the higher sulfur coal. Upon notification Centralia Plant personnel took immediate action to stockpile the higher sulfur coal and switch the silo supply to the lower sulfur coal. CMC revised their operating procedures regarding coal sulfur levels and notification procedures to ensure this incident was not repeated. This exceedence constitutes one exceedence day. As provided in SWAPCA 90-934E, a violation is not triggered until two exceedence days are recorded in a month.

On June 17, 1997, the Centralia Plant notified SWAPCA that plant emissions exceeded the 1000 ppm SO_2 limit for three consecutive one-hour periods in the early morning. SO_2 emission concentrations were reported as 1045, 1019, and 1032 ppm, one hour averages. As provided in SWAPCA 90-934E, a violation is not triggered until two exceedence days are recorded in a month. This three hour exceedence constitutes one exceedence day. The exceedence was the result of high sulfur coal in the storage piles being fed into the coal silos during Unit #2 startup.

Visibility impacts

Sulfur dioxide emissions from combustion sources like Centralia Plant are reactive gases that form secondary aerosols and fine particulates in the atmosphere. A secondary particulate aerosol is formed when SO_2 gas reacts with hydroxyl radicals (OH^-) to create sulfuric acid. Sulfuric acid may also be formed in an aqueous-phase oxidation involving H_2O_2 or O_3 in clouds. Sulfate particles will be formed primarily by reaction of sulfuric acid with atmospheric ammonia or by cloud evaporation. The sulfate particles typically have an aerodynamic diameter less than 2.5 microns and are classified as fine particulate or $PM_{2.5}$. Over time, after SO_2 is emitted, a portion of the SO_2 will remain gaseous and a portion will be converted to sulfuric acid and further conversion to sulfates may occur. The relationship between SO_2 emitted from combustion sources and ambient $PM_{2.5}$ is nonlinear, and it is difficult to project the impact on $PM_{2.5}$ from changes in SO_2 emissions without the use of complex air quality models.

Sulfates contribute to visibility impairment in federally designated Class I areas in Washington. Visibility impacts have been identified by the National Park Service (NPS) and Forest Service (FS) as documented in the PREVENT study. Fine aerosols are the most effective contributors in scattered light and are the major contributors to light extinction. In most cases, the sulfate component of fine aerosol is the largest single contributor to light extinction. This is because sulfate, being hygroscopic, generally has a higher light extinction efficiency than other species due to associated liquid water. Visibility impacts and measured concentrations are described in detail in the Interagency Monitoring of Protected Visual Environments (IMPROVE) reports of February 1993 and the update of July 1996.

Visibility impairment is subject to regulation under the federal and state Clean Air Acts. Sulfates formed from Centralia Plant SO_2 emissions may contribute to visibility impairment from a layered haze or regional haze in Class I areas, along with many other area and point sources in Washington and Canada. A reasonable attribution study has not been performed by SWAPCA to determine the direct impacts from the Centralia Plant, but rather, the Federal Land Managers have preferred to utilize the negotiation process of the CDM group to achieve significant emission reductions and therefore demonstrate reasonable progress at visibility improvement for any impairment that may otherwise be attributable to the Centralia Plant. Further consideration of this aerosol is provided under the SO_2 section (Section 3) and the particulate matter section (Section 5).

Toxicity of the pollutant in question

Health concerns

Sulfur oxides measured as sulfur dioxide is a regulated pollutant for which a National Ambient Air Quality Standard (NAAQS) has been established to provide protection of the public to unhealthful levels of SO_2. A health risk assessment was performed by The Johns Hopkins University School of Public Health in Baltimore under the direction of Dr. Jonathan Samet in 1997 (Ref. 40). The study used a computer program called CALPUFF that estimated how sources like the Centralia Plant affect air quality. The study area covered a 150 mile radius centered around the Centralia Plant that serves as home to 5.5 million people. The study found the Centralia Plant to be a minor contributor to the total air pollution in the large cities of the area (e.g. plant emissions contribute approximately 0.5% to the annual average concentration of 27.35 $\mu g/m^3$ of PM_{10} in Seattle). Data were analyzed for impact on two groups that suffer most from air pollution, asthmatics and the elderly. The actual number of deaths in the area studied for 1990 was 34,760. After SO_2 scrubbers are operational, the calculated premature mortality from emissions from the Centralia Plant will drop to about 1 to 13 per year from a range of 3 to 35 per year without scrubbers. The risk estimates for mortality and morbidity associated with the Centralia Plant should not be construed as actual mortality and morbidity, but may be used for comparing to estimated risks from other air pollution sources (Ref. 40, p. 63-64). The majority of this calculated premature mortality is expected to occur in patients suffering from serious heart or lung conditions.

An evaluation of the relationship between postneonatal infant mortality and particulate matter in the U.S. has been performed (Ref. 37). The study recognized that a majority of infant deaths are unlikely to be influenced by air pollution levels because they occur too soon after birth or are due to causes clearly intrinsic to the infant, such as congenital anomalies. Postneonatal death (death of an infant over 27 days of age) is thought to be influenced more by the infant=s external environment than is mortality earlier in infancy. Several studies have suggested that sudden infant death syndrome (SIDS) is associated with exposures to environmental tobacco smoke. A total of almost 4 million infants born between 1989 and 1991 were included in one study which spanned 86 metropolitan statistical areas. After adjustment for confounding factors in this analysis, infants with high levels of PM_{10} exposure (40.1 to 68.8 $\mu g/m^3$) were at 10% higher risk of postneonatal death than were infants with low exposure (11.9 to 28.0 $\mu g/m^3$) (Ref. 37). As noted above in the Samet study, the annual average concentration of PM_{10} in the Seattle area is approximately 27.35 $\mu g/m^3$ (the low exposure group).

Public complaints

Odor

No odor complaints have been reported by the public in regard to emissions of SO_2 at the Centralia Plant. This is evidenced by a review of the plant files at SWAPCA.

Health complaints

Over the past several years, there was one health related complaint received by SWAPCA on November 10, 1993. The complainant alleged that high sulfur coal piles were spontaneously combusting releasing sulfur and soot into the air. In addition, this person was aware that soot cleaning was performed at night at the Centralia Plant which releases soot into the air that impacts this person. This person reportedly has gone to the hospital on several occasions because of respiratory problems.

Other nuisance complaints

A few nuisance complaints were recorded by SWAPCA in the early years of plant operation with respect to fine particulate matter but were not directly associated with SO_2.

Environmental effects

Several studies have been performed to determine if there is an environmental impact from emissions from the Centralia Plant. The first significant study was one performed in 1986 for the Washington State Legislature for acid rain impacts. The results of that study indicated no acid rain impacts (Ref. 19). The PREVENT study (Ref. 21) identified that emissions of SO_2 from the Centralia Plant may contribute to visibility impairment and acidification of lakes in the Mt. Rainier National Park, and emissions may have a contribution to negative growth impacts on the forests in Washington. The full extent of the contribution has not to date been evaluated by SWAPCA. Wet scrubbers, if installed to control SO_2 emissions, have some risk of creating a haze that may be visible near the stack after installation. Since the shutdown and closure of the ASARCO facility in Tacoma, Washington, the Centralia Plant is the single largest point source of SO_2 emissions in Washington. The total tons of SO_2 emitted into the atmosphere in western Washington has decreased in the last 10 years, or more, since the study for the legislature was performed. However, there is a considerable contribution of SO_2 from mobile and area sources in western Washington which has increased significantly in recent years. The contribution of these sources relative to those of the Centralia Plant have not been fully evaluated by SWAPCA. A reasonable attribution study has not been performed by SWAPCA to determine the direct impacts from the Centralia Plant. Rather, in a collaborative process, the Federal Land Managers have preferred to utilize the negotiation process of the CDM group to achieve significant emission reductions and, therefore, demonstrate reasonable progress at reducing environmental effects that may be attributable to the Centralia Plant.

Availability of control equipment

Many technologies exist for control of this pollutant which have been incorporated into new plants and older facilities around the United States. The technology chosen to meet the criteria of "reasonably available" will determine what emission limit may be achieved by existing and available control technology. This determination is evidenced by the numerous entries in RACT/BACT/LAER Clearinghouse (Ref 47). A discussion of the numerous technologies can be found in the SO_2 detailed evaluation portion (Section 3.0) of this Technical Support Document.

Pollutant controlled at other sources

Sulfur dioxide is controlled at many other older and newer facilities in the United States. Information to support this is found in the RACT submittal document (Ref. 29) and the RACT/BACT/LAER Clearinghouse (Ref 47) and in Section 3.0 of this Technical Support Document.

Conclusion

Based on the quantity of emissions, the potential impact on visibility and public health, and the availability of additional control equipment SO_2 is a pollutant of concern for which a RACT emission limit should be established.

2.3.2. NO_x Considerations

Amount or concentration of pollutant emitted

Emission inventory data and the RACT submittal submitted by the Centralia Plant indicated that nitrogen dioxide (NO_2) emissions from the facility for calendar years 1990, 1991, 1992, 1993, 1994, 1995, and 1996 were 23,761, 23,701, 20,198, 25,166, 22,268, 13,395, and 18,565 tons per year respectively, for Boilers #1 and #2, combined. Historical emission concentrations have been measured periodically by stack test to range between about 190 ppm and 350 ppm (0.35 to 0.65 lb/MBtu). Average annual NO_2 emission rates for 1995 for Units #1 & #2 were 0.42 and 0.45 lb/MBtu, respectively, and for 1996 were 0.43 and 0.45 lb/MBtu, respectively.

Ambient concentration

Monitoring for nitrogen dioxide began in SWAPCA's region in 1997. An eight-month NO_2 average of 0.013 ppm has been measured in Vancouver, WA through August 1997. Ambient air monitors for nitrogen dioxide (NO_2) were located in Seattle from 1980 to 1986, and NO_2 and nitric oxide (NO) monitors were reestablished in Seattle and southeast King County in 1995. No exceedences of the 0.053 ppm, annual average, NO_2 ambient air quality standard have been recorded at any of these sites. The highest annual averages were 0.04 ppm in 1981 and 1982 at the Union Station site in Seattle (Ref. 38). There is little ambient data for NO_2 in Washington as there have not been associated air quality problems which would justify the costs or need for such monitoring. In the United States, the highest ambient NO_2 concentrations are found in southern California and other large urban areas. There have been no exceedences of the NO_2 NAAQS since 1991 in the United States.

An ambient air monitoring study at several sites was conducted by Washington State University before and after the startup of Centralia Plant in 1971. NO_x monitoring was not conducted before start-up of the plant, however, continuous NO_x measurements were taken from 1972 to 1974 at four sites in the local area, both in the town of Chehalis and rurally. The annual average NO_x levels were all well below the ambient NO_2 standard of 0.053 ppm annual average. The highest annual average recorded during this study was at the Rainier Site in 1972 which had a value of 0.031 ppm.

Violations of an emission limit

There currently is no state or local emission limit for NO_x that would be a basis for the Centralia Plant to violate. In December 1996, the Centralia Plant applied for the Early Election option under the Phase I Acid Rain NO_x provisions (Title IV) for both units at the Centralia Plant. The Early Election option became effective starting January 1, 1997. Consistent with the Early Election option, the enforceable Acid Rain limitation for each unit is 0.45 lb NO_x/MBtu annual average for the years 1997 through 2007. Compliance with this emission limit is currently achieved through good operating practices, not by additional control equipment.

Visibility impacts

Visibility is degraded by light scattered into and out of the line of sight and by light absorbed along the line of sight. Light absorption results from gases and particles. Nitrogen dioxide (NO_2) is the only major light-absorbing gas in the lower atmosphere. Its strong wavelength-dependent scatter causes yellow-brown discoloration if present in sufficient quantities. Soot (elemental carbon) is thought to be the dominant light-absorbing particle in the atmosphere (Ref. 68, p. 1-8). Nitrogen oxide emissions from combustion sources like Centralia Plant are reactive gases that may form secondary aerosols and fine particulates in the atmosphere. The secondary particulate aerosol is formed when NO_2 reacts with hydroxyl radicals (OH^-) during daylight hours to form nitric acid; during nighttime hours NO_2 reacts with ozone to form nitric acid. The nitric acids react with ammonia in the atmosphere to form ammonium nitrate particulate. The nitrate particulates typically have an aerodynamic diameter less than 2.5 microns and are classified as fine particulate. Further consideration of this aerosol is provided under the particulate matter section (Section 5.0).

Based on estimated visibility degradation in Mount Rainier National Park originating from present NO_x emissions at the Centralia Plant, the improvement in visibility from NO_x reductions of 15% to 50% is expected to be small. Present NO_x emissions contribute about 1% or less to non-Rayleigh scattering at Mount Rainier, so the available margin for improvement is likewise small (Ref. 29, p. 32). Visibility improvements may be difficult to observe because of growth in the Seattle-Tacoma urban area offsetting the gains shortly after they are achieved, but this does not mean such efforts are fruitless. Reductions in NO_x emissions at the plant can alleviate further degradation of visibility in nearby Class I areas for that portion of degradation that could be attributed to the Centralia Plant.

During the CDM meetings, the FLMs emphasized that NO_x (as aerosol nitrate) has much less impact on visibility than SO_2 (as sulfate aerosol) and called for much greater emphasis on SO_2 reductions.

A reasonable attribution study has not been performed by SWAPCA to determine the direct impacts of NO_x emissions from the Centralia Plant. Rather the Federal Land Managers have preferred to utilize the negotiation process of the CDM group to achieve NO_x emission reductions and, therefore, visibility improvement and reduction in acid deposition and aquatic systems acidification.

Toxicity of the pollutant in question

Health concerns

Nitrogen dioxide is an oxidant gas of low solubility, which penetrates to the small airways and alveoli of the lung. It produces a wide range of health effects including increased risk for respiratory infections, respiratory symptoms, reduces lung function, and exacerbation of chronic respiratory diseases. There are only limited epidemiologic data which remain inconclusive, largely because of problems arising in attempts to separate the effects of NO_2 from those of other pollutants (Ref. 40, p. 17).

Nitrogen oxides are formed during combustion of fuel and air. In sufficiently high concentrations, nitrogen oxides in ambient air can irritate the lungs, lower resistance to respiratory infections such as influenza and increase the symptoms in asthmatics. The effects of short-term exposure are still unclear, but continued or frequent exposure to higher concentrations than found in ambient air may cause increased incidence of respiratory disease in children. In response to these effects, the EPA established a National Ambient Air Quality Standard (NAAQS) of 0.053 ppm annual average to provide protection of the public to unhealthful levels of NO_2, the predominant form of NO_x. Washington has a state ambient air quality standard of only two decimal places, 0.05 ppm, yet it is also stated to be 100 $\mu g/m^3$, equivalent to the federal standard. No exceedence of the NAAQS has been identified in the area of influence from the Centralia Plant.

In the 1997 study entitled "An Assessment of the Health Risks Due to Air Emissions from the Centralia Power Plant" (Ref. 40), emissions from the Centralia Plant were modeled to generate hourly and annual pollutant concentrations for a grid of points in a region within 150 miles of the plant stretching roughly from Bellingham, Washington to Salem, Oregon. The health effects assessed in this study arise from exposures to particles, including acidic particles, and NO_x both before and after installation of emission controls. Some of the NO_x converts to nitrate (NO_3), a fine aerosol assumed to all be less than 2.5 μm in diameter that will primarily be in the form of ammonium nitrate (Ref. 40, p. 6-7).

Modeled pollutant concentration increments were combined with population data to produce increments in exposure. The population exposure increments were combined with risk coefficients describing the mortality or morbidity associated with the pollutants to characterize the risk from plant emissions. The risk estimates for mortality and morbidity associated with the Centralia Plant should not be construed as actual mortality and morbidity, but may be used for comparing to estimated risks from other air pollution sources (Ref. 40, p. 58). The effect on health impacts resulting from NO_x emission reduction cannot be easily isolated. Quantified results are provided for fine particulate matter, which includes nitrates as well as other aerosols (see '4.1.3 and '5.1.3 of this Technical Support Document).

Public complaints

Odor

There have been no complaints received by SWAPCA in regards to odor from NO_x emissions from the Centralia Plant.

Health complaints

There have been no health related complaints received by SWAPCA that could be attributed to NO_x emissions from the Centralia Plant.

Other nuisance complaints

There have been no nuisance complaints received by SWAPCA as a result of NO_x emissions from the Centralia Plant.

Environmental effects

Of the six or seven oxides of nitrogen, nitric oxide (NO) and nitrogen dioxide (NO_2) are important air pollutants. Although nitrous oxide (N_2O) is commonly present in the lower atmosphere (formed by biological action at the earth=s surface) it is not considered an air pollutant though it is identified as a greenhouse gas that contributes to global warming. Neither NO nor NO_2 causes direct damage to materials; however, NO_2 can react with moisture present in the atmosphere to form nitric acid, which can cause considerable corrosion of metal surfaces. Nitrogen dioxide absorbs visible light and at a concentration of 0.25 ppm will cause appreciable reduction in visibility. NO_2 at a concentration of 0.5 ppm for a period of 10 to 12 days has suppressed growth of such plants as pinto beans and tomatoes (Ref. 39, p. 30).

Nitrogen dioxide acts as an acute irritant and in equal concentrations is more injurious than NO. However, at concentrations found in the atmosphere NO_2 is only potentially irritating and potentially related to chronic pulmonary fibrosis. Some increase in bronchitis in children (2 to 3 years old) has been observed at concentrations below 0.01 ppm. In combination with unburned hydrocarbons, the oxides of nitrogen react in the presence of sunlight to form photochemical smog. It is because of this chemical activity that the primary air quality standard for oxides of nitrogen has been set as 10 $\mu g/m^3$ annual average. The components of photochemical smog (photochemical oxidants) are the most damaging to plants and detrimental to human health (Ref. 39, p. 31).

There have been no specific studies undertaken by SWAPCA or other agencies since the early 1970s to ascertain the extent of any potential environmental effects from NO_x emissions from the Centralia Plant. The PREVENT study documented possible impacts from acid deposition and visibility impairment in Mount Rainier National Park from sources in western Washington and Canada (Ref. 21). A reasonable attribution study has not been performed by SWAPCA to determine the direct impacts from the Centralia Plant. Rather, in a collaborative process, the Federal Land Managers have preferred to utilize the negotiation process of the CDM group to achieve emission reductions of NO_x and, therefore, provide for visibility improvement.

Availability of control equipment

Numerous control options that are available and cost effective have been identified in the RACT submittal document and in the RACT/BACT/LAER Clearinghouse that could be applied to the Centralia Plant. Each option has various control levels and cost effectiveness that can be evaluated for application to the Centralia Plant.

Pollutant controlled at other sources

Nitrogen oxides are controlled at many other older and newer facilities in the United States. Information to support this is found in the RACT/BACT/LAER Clearinghouse. Controls have been provided on other facilities as a result of new source permitting as well as retrofit activities to reduce emissions after plants have been in operation. Rules have been established at the federal level under the provisions of the Acid Rain Program (Title IV of the Clean Air Act) to limit emission of nitrogen oxides from power plants on a national level. Several states including Washington have a state rule that is similar to the federal rule. In addition, several states (Pennsylvania, New Jersey, and other participating NESCAUM states) have rules in place regarding NO_x emissions from coal fired power plants.

NO_x Conclusion

Based on the amount of emissions, the potential for visibility and public health impacts, and the availability of additional commercially available control equipment, NO_x is a pollutant of concern for which a RACT emission limit should be established.

2.3.3. PM Considerations

Amount or concentration of pollutant emitted

Emission inventory data and the RACT submittal made by the Centralia Plant indicated that PM emissions from the Centralia Plant for calendar years 1993, 1994, 1995, and 1996 were 2944, 3240, 2177, and 3428 tons per year for Boilers #1 and #2, combined. Historical emission concentrations (most recent 6 years) have been measured periodically by stack test and have averaged 0.0154 gr/dscf (front and back half of EPA Method 5). The front half of the Method 5 sampling train employs a filter which captures fine particulate matter, such as coal ash, while the back half of this sampler is cooled to condense any liquid droplets that are in a vapor phase at elevated temperature and would pass through the front half filter. Front half only (EPA Method 5) emissions over this same period have averaged 0.002 gr/dscf for Unit #1 and 0.005 gr/dscf for Unit #2. Any uncollected ash exiting the Centralia Plant ESPs would be detected as front half particulate matter. The highest recorded front half value for Unit #1 is 0.005 gr/dscf and the highest front half value for Unit #2 is 0.0243 gr/dscf. This Unit #2 value is substantially higher than other previously recorded values. This value is within current permitted values but is anomalous. The second highest value recorded for Unit #2 was 0.0061 gr/dscf. The current configuration for control of particulate matter at the Centralia Plant is two electrostatic precipitators (ESPs) in series. This combination of controls provides 99%+ control efficiency for particulate matter. All particulate matter released to ambient air for purposes of this evaluation is considered to be PM_{10}. This is reasonable because of the unique control strategy employed at the Centralia Plant. In addition, sulfate and nitrate aerosols are considered to be particulate matter, but would not be effectively controlled by traditional particulate matter collection devices because they are emitted in gaseous forms (SO_2 and NO_2) and then later through a complex atmospheric chemical reaction become secondary particles. It is these aerosols that would contribute most significantly to visibility impairment, acid deposition, and potential health impacts.

Ambient concentration

Before 1987 the National Ambient Air Quality Standards (NAAQS) for Total Suspended Particulate (TSP - #100 Φm) were 75 $\Phi g/m^3$ geometric mean primary, and 60 $\Phi g/m^3$ geometric mean secondary, and 260 $\Phi g/m^3$ 24-hour primary and 150 $\Phi g/m^3$ 24-hour secondary standard based on the second highest value. In 1987, the EPA established NAAQS for particulate matter having an aerodynamic diameter of 10 microns (Φm) or less, referred to as PM_{10}. The annual PM_{10} NAAQS is an arithmetic mean not to exceed 50 $\Phi g/m^3$, and 24-hour standard is 150 $\Phi g/m^3$, not to be exceeded more than once per year. The Washington State ambient air quality standards for PM_{10} are identical to the federal standard.

There are no operating PM_{10} monitors in the Centralia Plant local area. The closest ambient monitor is in Lacey, at Mountain View Elementary School. In Lacey, PM_{10} levels have been trending down in recent years and are now less than half of the ambient standards. Ambient PM_{10} trends in the Seattle, Tacoma, Lacey, Longview, and Vancouver areas, as shown in the WDOE Annual Air Quality Reports are all downward. All stations in SWAPCA's jurisdiction have reported ambient levels less than one half of the 24-hour and annual standards. The Olympia-Lacey-Tumwater area is the only area that is in non-attainment status with the PM_{10} standard. This area has not exceeded PM_{10} standards since 1990 and is waiting for final EPA approval of redesignation.

Violations of an emission limit

The opacity limit for the Centralia Plant is established at the State standard of 20%. This limit is applicable during the mode of normal operations and does not include startup and shutdown, or upset conditions. The existing ESPs maintain opacity at approximately 5% during normal operations. Periodically, the ESPs are deenergized as a routine maintenance activity to manually rap the precipitator plates. This manual rapping improves the overall long-term efficiency of the ESPs. If not performed, the efficiency of the ESPs degrades thus allowing opacity to increase from 5% up to as high as 20% where additional maintenance would be required and overall PM emissions increase. Periodic manual rapping which results in short term excursions above the 20% limit is the preferred operational mode because it provides for lower overall PM emissions. This is provided for in the regulations. During startup, the ESPs are not on-line due to minimum temperature requirements. Opacity above 20% is experienced during this time but is not a violation of the standard because of regulatory provisions allowing excess emissions under such circumstances. During normal shutdown the temperature of the gases through the ESPs can usually be maintained until there is no fuel in the boiler and opacity is at a minimum. However, there are a few modes of low power operation where the minimum temperature requirements can not be maintained in the ESPs and they will be off-line. Short term excursions above 20% opacity could be experienced during this time. Again this is allowed as part of the design configuration of the ESPs.

There have been no opacity violations in the recent years. During initial startup of the plant, the Koppers ESPs did not function as designed and there were numerous exceedences of the opacity limit. To ensure the plant could operate within the 20% opacity limit, a second set of ESPs in series (Lodge-Cottrell) were added in 1974.

In addition to the opacity standard, there is a Washington State and SWAPCA standard for particulate matter not to exceed 0.1 gr/dscf from any emission unit. Initial permitting of the facility established a limit not to exceed 0.06 gr/dscf for the main boilers. This limit applies to only the front-half portion (based on EPA Method 5) since it is based on a Koppers Company performance guarantee for ESPs, which are not effective at controlling the condensible portion of particulate matter (back half). Except for the problems encountered during initial startup of the plant with the Koppers ESPs, compliance with the 0.10 gr/dscf and 0.06 gr/dscf limits has been achieved since the installation of the second set of ESPs (Lodge-Cottrell). Table IV-2 of the RACT submittal (Ref. 29, p. 127) summarizes the results of particulate matter testing at the Centralia Plant. These test results indicate compliance with excess margin. The average concentration for Unit 1 since 1989 is 0.0020 gr/dscf and the average concentration for Unit 2 since 1989 is 0.0058 gr/dscf. The highest recorded value in this time period was 0.0243 gr/dscf on Unit 2 in August of 1996, well below the standard. This is attributed to the unique configuration of the plant with the installation of two full capacity ESPs in series. No other coal fired power plant in the United States has this configuration. Collection efficiency for these combined ESPs is in excess of 99.9% for non-condensible PM, and greater than 99.6% on average for all PM including condensible particles.

Visibility impacts

As noted in PREVENT (Ref. 21), even though sulfate accounted for only 20-30% of the fine mass ($PM_{2.5}$) measured at Tahoma Woods and Marblemount, it was estimated that it made up about 50% of the non-Rayleigh extinction budget. Organic plus light-absorbing carbon contributed about another 15-20%, while nitrates and coarse mass contributed about 10% to the extinction budget. Fine soil was less than 1%. It was expected that the highest concentrations of organics would be found near a forest fire with decreasing concentrations as one moves radially away from the particle source. PM_{10} emissions from the Centralia Plant account for approximately 1% of the total PM_{10} emitted in western Washington and Oregon.

In the Addendum to PREVENT, conclusions indicated that organics and light absorbing carbon were the single largest contributors to measured fine mass and are the second largest contributor to visibility reduction in Mount Rainier National Park. The empirical regression model attributed most organics and light absorbing carbon to either lead or bromine both of which were shown to be primarily associated with transportation activity. Very little carbon was associated with potassium which was mostly linked to burning. The chemical mass balance (CMB) model suggests that about 50% of the organics at Mount Rainier National Park have an urban transportation origin with fire-related activity accounting for only about 10%. On the other hand, almost 40% of organics are associated with the soil signature suggesting substantial re-entrainment of organic material along with wind blown dust. Light absorbing carbon is also most closely associated with the transportation signature at a greater than 60% contribution. Again only a small fraction (13%) of light absorbing carbon was linked to burning. The soil signature accounted for about 25% of light absorbing carbon.

Conclusions from the PREVENT (Ref. 21) and IMPROVE (Refs. 67 & 68) reports, which analyzed monitored PM values in and around Mount Rainier National Park and other Class I areas in Washington and considered the actual PM emissions from the Centralia Plant, did not identify a significant impact on visibility due to emissions of primary particulate from the Centralia Plant. The majority of the impacts on visibility were attributed to sulfates, nitrates and organics.

Toxicity of the pollutant in question

Health concerns

Fly ash, the major portion of particulate matter emitted from Units #1 and #2 (excluding gaseous pollutants that form aerosols), are not listed on the Toxic Air Pollutant list in WAC 173-460. The issue of health concerns with regard to particulate matter emissions has come under scrutiny recently by EPA with the issuance of a new ambient air quality standard for particulate matter #2.5 Φm ($PM_{2.5}$). Testing of stack emissions by Method 201A indicated that $PM_{2.5}$ accounts for only 17% of the primary particulate matter (excluding particles that condense below the Method 5 reference temperature of 248∀25EF and secondary aerosols) emissions from the plant. PM_{10} emissions account for about 81% of the primary particulate matter emissions (Ref. 29, p. 145).

In addition to the fly ash, a portion of the particulate matter emitted is in the form of condensible particulate matter, such as nitric acid and sulfuric acid formed from the NO_x and SO_2 emissions found in the combustion flue gas. The sulfates and nitrates form in the atmosphere hours or days after the gases are emitted from the Centralia Plant. The particulates form through complex atmospheric chemistry, and become part of ambient particulate concentrations.

In the 1997 study entitled "An Assessment of the Health Risks Due to Air Emissions from the Centralia Power Plant", Samet et al. assess the risk in western Washington and northwest Oregon from increments to pollutant concentrations due to Centralia Plant emissions. Exposure to particulate matter includes both primary combustion emissions and secondary particulate matter from formation of sulfate (SO_4) and nitrate (NO_3). The secondary aerosols are assumed to all be $PM_{2.5}$ and typically are combined with ammonium in the atmosphere. The risk assessment identified sulfates as the largest component of total particulate concentrations, with secondary nitrates and primary particles emitted directly from the plant as smaller components (Ref. 40).

In a 1996 report "Breathtaking: Premature Mortality due to Particulate Air Pollution in 239 American Cities", (Ref. 57) the Natural Resources Defense Council (NRDC) estimated that 307 annual cardiopulmonary deaths were attributable to particulate matter air pollution in the Portland Metropolitan Statistical Area (MSA). For the Seattle-Everett MSA, NRDC estimated 501 annual cardiopulmonary death from particulate matter, and for the Tacoma MSA it estimated 195 deaths. None of these Pacific Northwest MSAs were among the top 50 in the country for attributable mortality (Ref. 57).

In their 1992 report "Air Quality Analysis and Related Risk Assessment for the Bonneville Power Administration's Resource Program Environmental Impact Statement", Glantz et al. estimated annual cumulative exposures based on 1991 emissions data at the Centralia Plant. For population levels projected for the year 2000, the total cumulative exposure was estimated to be 20,759 person-$\mu g/m^3$ due to total suspended particulate matter. However conversion of gaseous SO_2 and NO_x to their aerosol forms sulfate and nitrate, respectively, is not accounted for in the dispersion model. This study defined half of the particle mass as having a diameter of less than 1 μm (Ref. 41).

An evaluation of the relationship between postneonatal infant mortality and particulate matter in the U.S. has been performed. The study recognized that a majority of infant deaths are unlikely to be influenced by air pollution levels because they occur too soon after birth or are due to causes clearly intrinsic to the infant, such as congenital anomalies. Postneonatal death (death of an infant over 27 days of age) is thought to be influenced more by the infant=s external environment than is mortality earlier in infancy. Several studies have suggested that sudden infant death syndrome (SIDS) is associated with exposures to environmental tobacco smoke. A total of almost 4 million infants were included in this analysis. After adjustment for confounding factors, infants with high levels of PM_{10} exposure (40.1 to 68.8 $\mu g/m^3$) were at 10% higher risk of postneonatal death than were infants with low exposure (11.9 to 28.0 $\mu g/m^3$).

Public complaints

Odor

There have been no complaints received by SWAPCA in regards to odor issues from particulate matter emissions from the Centralia Plant.

Health complaints

Over the past several years, one health related complaint was received by SWAPCA on November 10, 1993. The complainant alleged that high sulfur coal piles were spontaneously combusting releasing sulfur and soot into the air. In addition, this person was aware that soot cleaning was performed at night at the Centralia Plant which releases soot into the air that impacts this person. This person reportedly has gone to the hospital on several occasions because of respiratory problems.

Other nuisance complaints

There have been no nuisance complaints received by SWAPCA from particulate matter emissions from the Centralia Plant since the early days of initial operation when the ESPs were not functioning properly.

Environmental effects

There have been no specific studies undertaken by SWAPCA or other agencies to ascertain the extent of any potential environmental effects from particulate matter emissions from the Centralia Plant since the initial permitting. The PREVENT study (Ref. 21) documented possible impacts from acid deposition and visibility impairment in Mount Rainier National Park from sources in western Washington. A reasonable attribution study has not been performed by SWAPCA to determine the direct impacts from the Centralia Plant. Rather, the Federal Land Managers have preferred to utilize the negotiation process of the CDM group to achieve emission reductions and, therefore, visibility improvement.

Availability of control equipment

The Centralia Plant controls particulate matter emissions through the use of two commercial sized electrostatic precipitators (ESPs) in series. ESPs are the most common devices used to control particulate emissions from coal fired boilers in the generation of electricity. Performance of these units at the Centralia Plant averages about 99.9% overall collection efficiency for non-condensible particles. Additional or other control equipment exists that could be used to control particulate matter emissions such as cyclones, high energy scrubbers, or side stream separators. Because these technologies will not provide the level of control currently achieved by the existing controls they were not evaluated further. The RACT submittal document identified two additional control options that were considered for evaluation at Centralia Plant. These include baghouse retrofit and flue gas conditioning. These technologies could be added to the existing ESPs. Due to the high efficiency nature of the existing ESPs there is little additional improvement to be gained by the addition of a third control unit. These additional two technologies were addressed in detail in the RACT submittal document (Ref. 29).

Pollutant controlled at other sources

All coal fired units of this type and size in the United States have some type of particulate matter controls as identified in the EPA electric utility draft report. Recent entries in the RACT/BACT/LAER Clearinghouse indicate that fabric filtration (baghouses) and ESPs have been determined to meet BACT, PSD and NSPS requirements at a threshold of at least 99% control efficiency.

PM Conclusions

Potential emissions from the Centralia Plant without the use of control equipment would be approximately 415,000 tons per year. The Centralia Plant was originally permitted with one set of

ESPs. Due to poor performance of the first set of ESPs and the inability to meet the Washington State standard of 0.10 gr/dscf and the SWAPCA established limit of 0.06 gr/dscf, a second ESP for each unit was added in series. These two units combined provide approximately 99.9% control efficiency for non-condensible PM. Current emission limits are established at 0.06 gr/dscf (front half only). Over the past six years, source test data indicates that average emissions from both units, combined, are 0.0036 gr/dscf.

RACT is defined as the lowest emission limit that a particular source or source category is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. Based on the large differential between actual emissions and the existing emission limit, and the capability of the existing equipment, PM is a pollutant of concern for which a RACT emission limit should be established.

2.3.4. CO Considerations

Amount or concentration of pollutant emitted

Emission inventory data and the RACT submittal made by the Centralia Plant indicated that CO emissions from the Centralia Plant for calendar years 1993, 1994, 1995, and 1996 were 1678, 1791, 1147, and 1371 tons per year for Boilers #1 and #2, combined, under normal operations. Historical emission concentrations have been measured periodically by stack test and have averaged approximately 20-30 ppm. Source test emission data from 1996 provided results of 1.1 ppm @ 15% O_2 for Unit 1 and 28.0 ppm @ 7% O_2. Concentrations vary significantly hour to hour depending on numerous factors. Many of the factors that influence NO_x also influence CO. These factors include excess air levels, boiler cleanliness, flame temperatures, load changes, fuel composition, coal mill operation (coal flow rate, number in service, fineness settings, primary air flow rates), unit load, and boiler design factors.

It is likely that low NO_x burner technology will be installed to control emissions of NO_x from the Centralia Plant. Installation of these burners will likely result in an increase in CO emissions. Early estimates indicate that CO emissions may double from the facility (Ref 42, item 31). Even though such emissions are not expected to cause an ambient impact or health risk, additional emphasis will be necessary to ensure good combustion within the boilers is maintained. High emissions of CO are indicative of poor combustion. Poor combustion results in increased fuel consumption and more fuel cost for the facility. There is substantial economic incentive for the boilers to be operated at maximum combustion efficiency (low CO). One point demonstrating the importance of CO monitoring to efficient operation is that each boiler is equipped with three CO monitors. One CO monitor is installed as part of the stack gas monitoring equipment; the other two are located in each of the two boiler discharge ducts. These monitors are used by the Centralia Plant operators to ensure good combustion is maintained.

Ambient concentration

The federal and state ambient air quality standard for CO is 9 ppm - 8 hour average and 35 ppm - 1 hour average (9 ppm is equivalent to 10,000 Φg/m^3, 35 ppm is equivalent to 40,000 Φg/m^3). As provided in SWAPCA's 1995 Annual Report, approximately 30,947 tons of CO were emitted in Lewis County with on-road vehicles being the largest source category. The Lewis County area is attainment with the ambient air quality standards. PacifiCorp has conducted air modeling for emissions of CO from the Centralia Plant. Projections of the Centralia Plant's impact on ambient CO concentrations, using the ISC3 model, indicate that the highest one hour concentration is 19.4 Φg/m^3 and the highest 8-hour concentration is 4.9 Φg/m^3. The areas of highest concentration are located within a few miles of the plant as shown in modeling results presented in the RACT submittal document.

Violations of an emission limit

The New Source Performance Standard (NSPS) for electric utility boilers at 40 CFR 60.40 et seq. and 40 CFR 60.40a et seq. does not include a standard for CO. There was no CO limit established for the Centralia Plant under the original construction approval or subsequent Regulatory Orders from SWAPCA, and there is no state or local limit established for CO other than the ambient air quality standard. Therefore, because there is no established limit, there has been no violation of a state or local limit. Further, based on modeling results, there has been no violation of the state and federal ambient air quality standard as a result of CO emissions from the Centralia Plant.

Visibility impacts

Visibility impairment is caused by the scattering and absorption of light by suspended particles and gases. Three pollutants (primary particulates, NO_x and SO_2) have been identified as the primary contributors to visibility impairment. CO has not been identified to be a contributor to visibility impairment, therefore no impact or impairment is projected and further analysis has not been performed or required. (Ref. 33, p. 3). CO does not contribute to visibility impacts.

Toxicity of the pollutant in question

Health concerns

The levels of CO emitted from the Centralia Plant are extremely low in comparison to the health based ambient air quality standards. The highest concentrations modeled for the Centralia Plant were identified as 19.4 Φg/m^3, the highest one hour concentration, and 4.9 Φg/m^3, the highest 8-hour concentration. The federal and state ambient air quality standard for CO is 9 ppm - 8 hour average and 35 ppm - 1 hour average (9 ppm is equivalent to 10,000 Φg/m^3, 35 ppm is equivalent to 40,000 Φg/m^3). The modeled values are well below any level which would cause a health risk and these values were identified in areas close to the Plant that are sparsely populated.

Public complaints

Odor

CO is an odorless, colorless gas. Due to inherent nature of this gas there are no complaints which have been received by SWAPCA in regards to odors issues from carbon monoxide emissions from the Centralia Plant.

Health complaints

There are no health related complaints which have been received by SWAPCA that could be attributed to CO emissions from the Centralia Plant.

Other nuisance complaints

There are no other nuisance complaints which have been received by SWAPCA from carbon monoxide emissions from the Centralia Plant.

Environmental effects

There are no known impacts that have resulted from CO emissions from the Centralia Plant. Due to the relatively low modeled impacts, none are expected. Because of the low modeled impacts no specific studies have been undertaken by SWAPCA to specifically evaluate the environmental impacts from such emissions.

Availability of control equipment

The EPA's RACT/BACT/LAER Clearinghouse lists control technology for CO for BACT and/or PSD determinations but none for RACT for coal combustion sources. The use of good combustion practices, combustion controls, and boiler design and operation have been identified to meet BACT-PSD requirements in recent years. Additional technology is available for non-coal fired applications such as CO oxidation catalysts, however, no application of post-combustion controls has been identified on coal-fired sources, even on a pilot or demonstration basis. Post combustion controls for CO would have to overcome issues of particulate loading and sulfation in addition to proper temperature and moisture conditions for a particular technology. Sulfation is a chemical reaction that results in sulfur poisoning of the oxidation catalyst. Relating costs for other combustion sources for control of CO indicates that, if it were possible, the cost would be prohibitively high. At this point in time, good combustion controls is the only feasible control option that is commercially or economically available.

Pollutant controlled at other sources

There are no known instances where post combustion controls are included on a coal-combustion unit in the United States or in other countries. Operators of these plants rely on good combustion practices and controls to maintain low levels of CO emissions. CO is a "controlled pollutant" at other coal-fired power plants however, the controls are process related, not add-on or post-combustion equipment. Such controls are currently used at the Centralia Plant.

CO Conclusion

Based on the total annual emissions, and an expected increase in CO emissions (likely > 1,000 tons/yr) exceeding the PSD threshold of 100 tons/yr (even though PSD is not triggered) as a result of low-NO_x combustion modifications, CO is a pollutant of concern for which a RACT emission limit should be established.

2.3.5. VOC Considerations

Amount or concentration of pollutant emitted
In the Centralia Plant boilers, combustion occurs at temperatures of approximately 3000EF, which results in near complete destruction of any volatile organic compounds. The combustion gas temperature is reduced to 300EF at the exit of the boiler air preheater. Some products of incomplete combustion in the form of residual VOCs may exit the boiler and be emitted in the stack. The end result is that the number of tons per year of emissions is relatively small in comparison to the other emissions and the size of the facility. Emission inventory data and the RACT submittal made by the Centralia Plant indicated that VOC emissions from the Centralia Plant for calendar years 1993, 1994, 1995, and 1996 were 197, 209, 134.4, and 164.4 tons per year for Boilers #1 and #2, combined, under normal operations. Historical emission concentrations have not been measured by stack test, but instead, emission inventory numbers have been generated using EPA AP-42 emission factors for coal-fired power plants and are based on the combustion of a "generic" coal. Because of the specific characteristics of Centralia Mining Company (CMC) coal, the Centralia Plant emissions are likely less than the values obtained from the AP-42 emission factors. Using the AP-42 emission factors, at full load conditions, each stack's emissions may be calculated as 0.06 lb VOC/ton of coal burned times 444 tons coal/hr = 26.6 lb/hr. This calculates to 116.5 tons per year. Concentrations vary significantly hour to hour depending on numerous factors. Many of the factors that influence NO_x and CO also influence VOC. These factors include excess air levels, boiler cleanliness, flame temperatures, load changes, fuel composition, coal mill operation (coal flow rate, number in service, fineness settings, primary air flow rates), unit load, and boiler design factors.

It is likely that low NO_x burners will be installed to control emissions of NO_x from the Centralia Plant. Installation of these burners will likely result in an increase in CO and VOC emissions. Early estimates indicate that VOC emissions will likely increase from the facility but the amount has not been quantified by the burner manufacturer. Even though VOC emission increases are not expected to cause an ambient impact or health risk, additional emphasis will be necessary to ensure good combustion within the boilers, similar to CO. High emissions of VOC are indicative of poor combustion. Poor combustion results in increased fuel consumption and more fuel cost for the facility. There is substantial economic incentive for the boilers to be operated at maximum combustion efficiency (low VOC). There is no monitoring equipment for VOC at the Centralia Plant and source testing does not routinely include testing for VOC. Emissions of VOC are expected to follow the same trend as CO emissions, however, the quantity of emissions will be substantially lower. Certain volatile organic compounds are also identified as hazardous air pollutants (HAPs) or toxic air pollutants (TAPs) and will be addressed separately in the next section.

Ambient concentration
There is no federal and state ambient air quality standard for VOC. VOC is a precursor pollutant for ground level ozone for which an ambient air quality standard has been established. The exact role of VOC in ozone formation in the Lewis County area has not been established. As provided in SWAPCA's 1995 Annual Report, approximately 4069 tons of VOC were emitted in Lewis County with on-road vehicles and solvent use being the largest source categories. The Lewis County area is attainment with the ambient air quality standards.

Violations of an emission limit

The New Source Performance Standard (NSPS) for electric utility boilers at 40 CFR 60.40 et seq. (Subpart D and Subpart Da) does not include a standard for VOC. There was no VOC limit established for the Centralia Plant under the original construction approval or subsequent Orders issued by SWAPCA and there is no state or local limit established for VOC. The only applicable standard for this pollutant is the ambient air quality standard for ozone. Therefore, because there is no established emission limit there has been no violation of a state or local limit. Further, no violation of the ambient ozone standard has occurred with respect to emissions from the Centralia Plant.

Visibility impacts

Visibility impairment is caused by the scattering and absorption of light by suspended particles and gases. Three pollutants (primary particulates, NO_x and SO_2) have been identified as the primary contributors to visibility impairment. VOC has not been identified to be a contributor to visibility impairment, therefore no impact or impairment is projected and further analysis has not been performed or required. (Ref. 33, p. 3). VOCs, as a group, do not contribute to visibility impacts.

Toxicity of the pollutant in question

Health concerns

Volatile organic compounds are a regulated pollutant but there is no National Ambient Air Quality Standard. An air quality standard for hydrocarbons was established in the early 1970s but was withdrawn late in the 1970s as the focus was shifted to individual hydrocarbon species and thus incorporated into standards to address hazardous air pollutants. VOCs were not totally eliminated from concern as a group; they were unmanageable as a group because of the significant differences in composition and effects from compound to compound. VOCs as a category are a contributing pollutant to ground level ozone under certain favorable atmospheric conditions. Some VOCs are more reactive than others in contributing to ozone and therefore any health affects. A National Ambient Air Quality Standard has been established to provide protection of the public to unhealthful levels of ozone but there is no direct correlation to limits on VOCs. No exceedence of the ozone NAAQS has been identified in the area of influence from the Centralia Plant.

VOCs, or hydrocarbons, do not appear to cause any appreciable corrosive damage to materials. Of all the hydrocarbons, only ethylene has adverse effects on plants at known ambient concentrations. The principal effect of ethylene is to inhibit plant growth. To date, studies of the effects of ambient air concentrations of gaseous hydrocarbons have not demonstrated direct adverse effects upon human health. Studies of the carcinogenicity of certain classes of hydrocarbons do indicate that some cancers appear to be caused by exposure to aromatic hydrocarbons found in soots and tars. Identifiable airborne carcinogens are mostly polynuclear aromatic hydrocarbons. Unburned VOCs in combination with the oxides of nitrogen in the presence of sunlight form photochemical oxidants, components of photochemical smog, that do have adverse effect on human health and on plants (Ref. 39, p. 30).

Therefore, it is concluded that there are no immediate direct health impacts due to VOC emissions from the Centralia Plant.

Public complaints

Odor

There have been no complaints received by SWAPCA in regards to odors issues that could be attributed to VOC emissions from the Centralia Plant.

Health complaints

There have been no health related complaints received by SWAPCA that could be attributed to VOC emissions from the Centralia Plant.

Other nuisance complaints

There have been no other nuisance complaints received by SWAPCA that could be attributed to VOC emissions from the Centralia Plant.

Environmental effects

There have been no specific studies undertaken by SWAPCA or other agencies that have focused on VOC emissions from the Centralia Plant to ascertain the extent of any potential environmental effects from VOC emissions from the Centralia Plant. The PREVENT study (Ref. 21) documented possible visibility impairment in Mount Rainier National Park from sources in western Washington. A visibility impairment evaluation has not been performed by SWAPCA regarding the direct impacts of VOC emissions from the Centralia Plant because the Federal Land Managers have preferred to utilize the negotiation process of the CDM group to achieve emission reductions and therefore obtain reasonable progress at visibility improvement.

Availability of control equipment

The EPA's RACT/BACT/LAER Clearinghouse lists control technology for VOC for BACT and/or PSD determinations but none for RACT for coal combustion sources. The use of good combustion practices, combustion controls, and boiler design and operation have been identified to meet BACT-PSD requirements in recent years. Additional technology is available for non-coal fired applications such as oxidation catalysts, however, no application of post-combustion controls has been identified on coal-fired sources, even on a pilot or demonstration basis. Post combustion controls for VOC would have to identify new or innovative ways to resolve current problems with particulate loading and sulfation in addition to proper temperature and moisture conditions for a particular technology. Sulfation is a chemical reaction that results in sulfur "poisoning" of the oxidation catalyst. Relating costs for other combustion sources for control of VOC indicates that, if it were possible, the cost would be prohibitively high for relatively low number of tons of pollutant compared to other pollutants emitted by this source. At this point in time, good combustion controls is the only feasible control option that is commercially or economically available. Generally any controls that may be used to control emissions of CO are likely to provide corresponding reductions in VOC emissions.

Pollutant controlled at other sources

There are no know instances where post combustion controls for VOCs are included on a coal-combustion unit in the United States or in other countries. Operators of these plant all rely on good combustion practices and controls to maintain low levels of VOC emissions. VOC is a "controlled pollutant" at other coal-fired power plants however, the controls are process related, not post-combustion or add-on equipment. Such processes are currently in use at the Centralia Plant.

VOC Conclusion

Based on the relatively small number of tons per year of VOC emissions compared to the other pollutants emitted by this source and the lack of availability of additional control equipment other than the currently employed process controls, VOCs are not considered to be a pollutant of concern for which a RACT emission limit should be established.

2.3.6. HAP/Toxic Considerations

Amount or concentration of pollutant emitted
Emission inventory data and the RACT submittal document prepared by the Centralia Plant indicated that hazardous air pollutant (HAP)/toxic air pollutant (TAP) emissions from Boilers #1 and #2, combined, under normal operations for calendar years 1993, 1994, 1995, and 1996 were 7.5, 8.2, 16.5, and 143.8 tons per year. The list of evaluated elements in the RACT submittal was a combination of elements from AP-42 and the EPA electric utility study draft report. The large emissions indicated in the 1996 data is the result of using an emission factor for HCl and HF based on uncontrolled emissions rather than the emission factor for scrubbed units as was presented in previous years. The 1996 emissions are more representative of actual emissions. The 1995 emission inventory incorrectly reported the amount of nickel emissions as 15,835 pounds instead of 20 pounds due to a calculational error. Total HAP emissions are estimated from Hazardous Element Sampling Train (HEST) testing, AP-42 and material balance calculations and through the use of EPA's draft electric utility study and Electric Power Research Institute (EPRI) emission factors.

Emission concentrations for certain elements were measured in a source test conducted in July 1992 with the implementation of a single HEST test. The elements tested for under HEST included: Be, V, Cr, Mn, Co, Ni, Cu, Zn, As, Se, Br, Mo, Ag, Cd, Sb, Ba, Hg, and Pb. Concentrations can vary significantly from hour to hour depending on numerous factors. HEST testing was performed for Unit 2 at full load and all CMC coal. Initial emissions data for 1993 was developed from results from the HEST test for most of the HAP elements, with AP-42 emission factors used for most of the other elements. Subsequent years have used a capacity factor ratio to reflect annual emissions.

HAP/TAP emissions can be more simply categorized into five categories identified as: (1) metals; (2) hydrogen chloride and hydrogen fluoride; (3) dioxin; (4) mercury; and (5) others. Many of the HAP/Toxic pollutants emitted by the Centralia Plant are metals in trace amounts contained in the coal ash. The ash is released during combustion and is collected in two tandem electrostatic precipitators. Emissions of the trace metals are generally very low due to the high collection efficiency of the existing ESPs. Modeling for the metal HAPs showed the impacts were all substantially below the Washington state acceptable source impact levels (ASILs) of WAC 173-460.

The largest single category of HAP/TAP emissions is that of hydrogen chloride (HCl) and hydrogen fluoride (HF). HCl emission estimates have been derived from EPRI emission factors based on the chlorine levels in the coal and HF emissions typically are 10-15% of the HCl emissions. Based on the EPRI emission factors, emission of HCl are calculated at 109.8 tons per year and HF at 27.4 tons per year for 1996. It is expected that actual emissions will be reduced by approximately 90% due to the installation of wet scrubbers for control of SO_2 emissions. The Centralia Plant is not subject to WAC 173-460 for control of toxic air pollutants unless there is a future modification that results in an increase in emissions. The Small Quantity Emission Rate (SQER) for both HCl and HF is 175 pounds per year. Even after 90% reduction in these emissions, the emission rates will be substantially greater than the SQER. However, modeling as presented in the RACT submittal indicates that results for HCl and HF are approximately 4% and 0.8% of the Acceptable Source Impact Level (ASIL) value from WAC 173-460 for HCl and HF, respectively. If the Centralia Plant were newly constructed in 1997, modeling results would indicate emissions of HCl and HF under current new source review requirements would be significantly below the ASIL values and acceptable from a health risk perspective.

Dioxin is a category of volatile organic compounds which may be released from coal combustion. The element evaluated for is identified as Chemical Abstract Service (CAS) number 1746-0106 and is chemically referred to as 2,3,7,8-Tetrachlorodibenzo-p-dioxin. The "normal" control strategy for control of dioxin emissions is incineration at elevated temperatures. Such conditions exist within the boilers at Centralia Plant. The EPA utility study estimates that the typical coal fired power plant emitted 0.00000014 tons per year (or 0.0012 pounds per year for both units at Centralia). The modeled value is approximately 0.33% of the ASIL of WAC 173-460 and therefore is considered insignificant.

Mercury (Hg) is a heavy metal that is only partially collected at the Centralia Plant by the ESPs because a portion of the mercury is emitted in vapor form. The 1996 emissions of mercury were estimated at 390 pounds per year. Studies have shown that ESPs, coal washing and wet scrubbers each remove a part of the potential mercury emissions. In EPA's electric utility study draft report, EPA concluded that particulate controls removed 0-82% of mercury with a median of 17%, coal cleaning removed an average of 29%, and the installation of wet scrubbers will remove an additional percentage which is yet unquantified. EPA currently is evaluating mercury emissions from all power plants for establishment of MACT controls. The estimated emissions of 390 pounds has been modeled and determined to be approximately 0.3% of the ASIL value of WAC 173-460. Because the emissions are significantly below the Washington State established ASIL and the fact that mercury is being considered for a MACT standard, emissions of mercury are not considered to be of concern.

The other pollutants that may be considered which have not been addressed by the above categories are n-nitrosodimethylamine and radionuclides. Emissions of these substances have never been tested for at Centralia Plant and are not included in AP-42. Insufficient information exists to be able to quantify emissions of these two substances. EPA has evaluated emissions of both these substances and dismissed each because of insignificant risk or that there is risk at only a few individual plants in the United States not including Centralia Plant. Therefore, based on the lack of quantifiable emissions data and the need for more complete studies, emissions of these elements are not considered to be of concern.

Ambient concentration

There is no federal and state ambient air quality standard for Hazardous or Toxic air pollutants. Most items in this category would be considered to be a form of particulate matter for which an ambient air quality standard has been developed, or in the case of VOC, are a precursor pollutant for ozone for which an ambient air quality standard has been established. The exact role of VOCs in ozone formation in the Lewis County area has not been established. No annual summary or ambient concentrations of hazardous or toxic pollutants has been compiled for the City of Centralia or Lewis County area.

Violations of an emission limit

The New Source Performance Standard (NSPS) for new electric utility boilers at 40 CFR 60.40a et seq. does not include a standard for HAPs or TAPs. There was no HAP or TAP limit established for the Centralia Plant under the original construction approval or subsequent Orders issued by SWAPCA and there is no state or local limit established for HAPs or TAPs for existing plants other than the ambient air quality standards for ozone and particulate matter. Therefore, because there is no established limit, there has been no violation of a state or local limit including no violation of the ozone or particulate matter standard.

Visibility impacts

Visibility impairment is caused by the scattering and absorption of light by suspended particles and gases. Three pollutants (primary particulates, NO_x and SO_2) have been identified as the primary contributors to visibility impairment. HAPs/TAPs have not been identified to be a contributor to visibility impairment, therefore no impact or impairment is projected and further analysis has not been performed or required. (Ref. 33, p. 3). Individual HAPs or TAPS may, individually contribute to visibility impacts but the emission of any one single element is so insignificant that no visibility impacts could be evaluated.

Toxicity of the pollutant in question

Health concerns

HAPs and TAPs are regulated pollutants but there is no National Ambient Air Quality Standard. HAPs and TAPs that are also VOCs are a contributing pollutant to ozone under certain favorable atmospheric conditions. A National Ambient Air Quality Standard has been established to provide protection of the public to unhealthful levels of ozone but there is no direct correlation to limits on VOCs. No exceedence of the ozone or particulate matter NAAQS has been identified in the area of influence from the Centralia Plant. Therefore, it is concluded that there are no immediate direct health impacts due to HAP/TAP (VOC) emissions from the Centralia Plant. Additional studies have been performed by EPA in the document titled Study of Hazardous Air Pollutant Emissions From Electric Utility Steam Generating Units -- Interim Final Report and in a study performed by EPRI. Inhalation cancer risks as determined in the EPA study were less than 1 in one million for all but two coal fired power plants. Long range transport identified levels as much as seven times higher for certain metals. In general, results from the EPA study did not identify particular elements that were of significant concern to proceed with immediate rulemaking. Therefore, the health risks from HAPs/TAPs as evaluated by EPA are considered to be acceptable without further significant analysis on an individual source at this time.

Public complaints

Odor

There have been no complaints received by SWAPCA in regards to odor issues from HAP or TAP emissions that would not be addressed as either VOC or particulate matter emissions from the Centralia Plant.

Health complaints

There have been no health related complaints received by SWAPCA that could be attributed to HAP or TAP emissions from the Centralia Plant.

Other nuisance complaints

There have been no other nuisance complaints received by SWAPCA from HAP or TAP emissions from the Centralia Plant.

Environmental effects

There have been no specific studies undertaken by SWAPCA or other agencies that have focused on HAP or TAP emissions from the Centralia Plant to ascertain the extent of any potential environmental effects from HAP or TAP emissions from the Centralia Plant. The PREVENT study documented possible visibility impairment in Mt. Rainier National Park from sources in Western Washington for those items that are VOCs or aerosols. A visibility impairment evaluation has not been performed by SWAPCA to determine the direct impacts from the Centralia Plant because the Federal Land Managers have preferred to utilize the negotiation process of the CDM group to achieve emission reductions and therefore obtain reasonable progress at visibility improvement.

Availability of control equipment

The EPA's RACT/BACT/LAER Clearinghouse does not list control technology for HAPS or TAPs for any type of evaluation. The current ESPs provide approximately 99% control of certain metals. Other pollutants that may be present in the boiler in gaseous form would be oxidized or otherwise destroyed in the process of combustion or oxidation. The installation of wet scrubbers for control of SO_2 emissions will provide up to 90% reduction of SO_2 and will have a significant reduction impact on certain of the HAP/TAP emissions passing through the ESPs. Many of the individual elements identified in the HAP list will be of insignificant quantities for control equipment to be technologically or cost effective. Emissions of mercury which may be controlled by the ESPs and coal washing are the subject of additional MACT rulemaking from EPA and will be considered under that program.

Pollutant controlled at other sources

There are no known instances where post combustion controls for HAPs or TAPs are included on a coal-combustion unit in the United States or in other countries expressly for the purpose of reducing HAPs or TAPs. Many facilities have particulate matter and SO_2 controls that provide substantial reductions of certain of the HAPs and TAPs. Emission control technology reviewed for criteria air pollutants has considered the potential reduction capability of each technology in their separate evaluations. No separate analysis has been performed to single out particular HAPs or TAPs.

HAP/TAP Conclusion

Based on the relatively small quantity of HAP/TAP emissions, the extremely varied nature of the individual HAPs and TAPs, and the lack of availability of additional specific control equipment other than the currently employed ESPs and proposed wet scrubbers, HAPs and TAPs are not considered to be pollutants of concern for which individual RACT emission limits should be established.

2.3.7. CO_2 Considerations

Amount or concentration of pollutant emitted

The 1997 RACT submittal indicated that CO_2 emissions from the facility for calendar year 1996 are estimated at 8.9 million tons per year. (Ref. 29, Appendix A) Data collected by continuous emission monitors (CEMs) at the plant for Acid Rain purposes indicates emissions of approximately 9.96 million tons per year. The difference in emissions is due, in part, to the flow measurement corrections necessary for the CEM. CO_2 emission concentrations have not been included as a part of a formal source test at the Centralia Plant. Concentrations emitted are a function of the carbon content of the fuel and will vary depending on the oxygen level maintained in the boiler. For Centralia Plant, CO_2 levels are generally around 14.5% concentration in the exhaust gases or about 145,000 ppm based on CEM data collected for the Acid Rain Program. Installation of a wet scrubber for SO_2 removal will likely increase CO_2 emissions by approximately 180,000 tons per year.

Ambient concentration

There is no federal or state ambient air quality standard for CO_2. CO_2 is not a regulated pollutant by SWAPCA or the state of Washington. Federal programs have been established by Congress and the Clinton Administration to reduce CO_2 emissions to 1990 levels on a national level from all sources on a voluntary basis by the year 2000. The first systematic ambient CO_2 measurements were made at Mauna Loa in Hawaii in 1958 which indicated a CO_2 background level of 315 ppm. Current global levels are reported to be approximately 350 ppm. Carbon dioxide accounts for approximately 0.035% of all constituents in ambient air. Daytime concentrations near the ground may be strongly depleted as a result of photosynthesis, while at night higher concentrations may accumulate under forest canopies as a result of plant and soil respiration. Neither SWAPCA nor Ecology has a program to monitor CO_2 in the ambient air or at individual sources.

In the U.S., over 1.6 gigatons (GT) of CO_2 is produced each year from power plants, but the industrial use of CO_2 is only 40 million tons per year, equivalent to about 2% of the CO_2 produced by the power plants. CO_2 is in a fully oxidized state after the combustion energy has been utilized. To reduce CO_2 to carbon requires about 80% of the energy that is generated from burning of typical coal (Ref. 34).

Violations of an emission limit

The New Source Performance Standards (NSPS) for electric utility boilers at 40 CFR 60.40a et seq. does not include standards for CO_2. There was no CO_2 limit established for the Centralia Plant under the original construction approval and subsequent Regulatory Orders issued by SWAPCA, and there is no state or local limit established for CO_2. Therefore, because there is no established limit, there has been no violation of a state or local limit or standard.

Visibility impacts

CO_2 does not contribute to visibility impairment therefore, there is no visibility impact.

Toxicity of the pollutant in question

Health concerns

There are no specific health concerns related directly to CO_2 emissions from the Centralia Plant. Global issues have been identified such as global warming that may have long term health impacts, however, insufficient information is available to draw a conclusion. Congress and the Clinton Administration have adopted two voluntary programs, under section 1605 of the Energy Policy Act and in the Climate Action Plan. The Energy Policy Act creates a voluntary reporting mechanism for reporting beneficial projects for reducing CO_2 emissions. The Climate Challenge program within the Climate Action Plan, is the public/private initiative launched by the U.S. Department of Energy and electric utilities to reduce greenhouse gas emissions.

Public complaints

Odor

CO_2 is an odorless gas. There have been no complaints received by SWAPCA in regards to odor issues from CO_2 emissions from the Centralia Plant.

Health complaints

There have been no health related complaints received by SWAPCA that could be attributed to CO_2 emissions from the Centralia Plant.

Other nuisance complaints

There have been no other nuisance complaints received by SWAPCA from CO_2 emissions from the Centralia Plant.

Environmental effects

Greenhouse gases such as CO_2 have been linked to global warming. The impact of global warming on our environment is a complex issue for which complete models have not yet been constructed. Because of the complex nature of this issue, insufficient data is available to draw specific conclusions around emissions from a specific emission source. CO_2 emissions are expected to be addressed on an international level first and then a national level within the United States. Until such time as specific guidance is available on a national level, more specific regulatory actions are not contemplated to determine direct impacts from the Centralia Plant to the local environment.

Availability of control equipment

No specific control equipment has been identified that could provide meaningful reduction of CO_2 emissions at the Centralia Plant. Options identified for potential consideration for coal-fired power plants include: (1) air separation, flue gas recycling, (2) amine scrubbing with cogenerated steam, (3) molecular sieves, (4) cryogenic fractionation, and (5) membrane separation. While potentially technically feasible, many of these options are not commercially available and each option has a significant energy penalty associated with it. The energy penalties range from 30% to 80%. In addition, once captured, there is no national policy on disposal. Costs per ton have been estimated in the range of \$60 to \$140 per ton of CO_2 avoided. These costs would result in an increase in electricity cost of 130% to 230%. At 8.9 million tons generated per year, the annual cost to Centralia Plant would be approximately \$890 million (Ref. 34).

Pollutant controlled at other sources

There are no known instances where pre- or post-combustion controls for reduction of CO_2 emissions are included on a coal-combustion unit in the United States or in other countries. There are a few plants in the United States where combustion gases have been captured and bottled to provide a source of commercial grade CO_2, but not for control of CO_2 emissions.

CO_2 Conclusions

CO_2 is a pollutant for which specific regulations have not yet been developed. There are no ambient or emission standards and there are no known health effects yet identified due to CO_2 emissions. In addition, there is no known technically or economically feasible control technology available to control this pollutant. Therefore, it is not practicable at this time to pursue establishment of a RACT emission limit for CO_2.

2.4 Emission Units and Pollutants Conclusions

1. The RACT submittal for SO_2 by the Centralia Plant in 1997 included detailed information relevant to control strategies for SO_2 based on the CDM Target Solution. This submittal focused on control strategies that would meet the CDM Target Solution and therefore offered a smaller universe of control strategies for analysis than were identified in the 1994/95 RACT review of the Centralia Plant. The control strategies evaluated in this section are those strategies that are expected to meet the CDM Target Solution, i.e., 10,000 tons per year and 250 ppm one-hour average, and only two reference point strategies for comparison. Therefore, the starting point for this SO_2 evaluation was the 90% reduction solutions and not the universe of control strategies including lesser control efficiencies as identified in the earlier RACT review. Because the basis for the evaluation in this SO_2 section had a criteria of needing to meet the CDM Target Solution, the outcome of this review was destined at the outset to exceed an evaluation based purely on RACT considerations. In addition, the CDM participants agreed to scrutinize the cost information with the objective of obtaining the maximum reductions possible short of precipitating a shutdown of the Centralia Plant. Therefore, the RACT emission limit established in 1995, and later withdrawn to ensure implementation of a lower SO_2 emission limit, has clearly been met without reidentifying RACT.

This approach to establishing an SO_2 emission limit is a decision made by SWAPCA because of the agreement within the CDM group (Federal Land Managers, EPA, Plant Owners, WDOE, PSAPCA) that as a minimum the CDM solution would be implemented. Upon review of the technologies and conclusions reached in the 1995 RACT Order, SWAPCA determined that a RACT emission limit similar to the previous determination (1.1 lb/million Btu), or probably a little less, is likely as an isolated RACT outcome. Therefore, nothing would be gained for the environment or the source by establishing a RACT emission limit that would not be more stringent than the limit established in the CDM process. Instead, the focus of the 1997 RACT effort has been to ensure inclusion of RACT for all pollutants of concern from the Centralia Plant and address concerns that were voiced during the process of finalizing the 1995 RACT determination. Therefore, the conclusions presented for SO_2 represent a CDM outcome that clearly exceeds the SO_2 limits established in the previous RACT Order SWAPCA 95-1787.

2. NO_x, PM and CO were determined by SWAPCA to be pollutants for which a RACT limit should be established.

3. Emission units for which the discharged pollutants were determined by SWAPCA to require RACT include only Boilers 1 and 2 (Unit #1 and Unit #2).

4. Pollutants and emission units evaluated for RACT were also evaluated by the CDM group even though the CDM group focused mostly on SO_2 because of the potential for visibility impact on Class I areas in Washington, and to a lesser degree on the other pollutants because of the smaller amount of emissions and the minor role they play in visibility impairment. The CDM group acknowledged that based on the uniqueness of two ESPs in series, additional control technology would not be appropriate for control of PM. A RACT emission limit would still need to be determined to validate this position. Because CO_2 does not contribute to visibility impairment, has no secondary ambient air quality standard, and has no present regulatory limits, further consideration of CO_2 control strategies was tabled by the CDM group.

Section 3.0

SO_2 RACT/CDM OUTCOME ANALYSIS

3.1 Impact of SO_2 Emissions on Air Quality

3.1.1 Facility Emissions

Annual emission inventories and quarterly emission reports submitted by the Plant to SWAPCA quantify the sulfur dioxide (SO_2) emissions from the plant=s two coal-fired units. The Centralia Plant's recent history of SO_2 emissions and the rate relative to heat energy input from fuel consumed is summarized as follows (Ref. 29, p.22):

Year	SO_2 Emissions (Tons/Year)	SO_2 Emission Rate
1988	67,270 tons	1.48 lb/MBtu
1989	61,755 tons	1.39 lb/MBtu
1990	58,297 tons	1.51 lb/MBtu
1991	59,450 tons	1.43 lb/MBtu
1992	69,488 tons	1.39 lb/MBtu
1993	63,960 tons	1.39 lb/MBtu
1994	67,435 tons	1.35 lb/MBtu
1995	52,941 tons	1.72 lb/MBtu
1996	78,272 tons	1.59 lb/MBtu

New CEMs were installed at the end of 1994 to comply with the Acid Rain Program. In 1995 (a very low production year) and 1996, the annual emissions and rate both increased because: (1) the coal sulfur content increased, and (2) the new CEMs measure slightly higher stack flowrate and SO_2 concentration than the previous monitors. Centralia Plant's 1-hour SO_2 stack concentrations have averaged 643 ppm from January 1, 1996 through June 30, 1997 for both units combined.

Data from the 1994 calendar year emission inventory for the state of Washington indicates approximately 93,700 tons of SO_2 were emitted into the air in western Washington by the 15 largest point sources while at least 4,760 tons were emitted from all on-road motor vehicles in western Washington. The Centralia Plant emitted 72% of the SO_2 emissions (67,435 tons) from the largest 15 point sources in western Washington.

3.1.2 Ambient Levels of SO_2 and Sulfates

1. The National Ambient Air Quality Standards (NAAQS) for sulfur dioxide include primary standards to protect public health with an adequate margin of safety and secondary standards to protect the public from adverse effects associated with the presence of SO_2 in the air, such as damage to crops, vegetation, and visibility. The state of Washington has established more stringent primary (i.e., human health-based) standards employing a shorter averaging time of one hour compared to the NAAQS short-term 3-hour averaging period. The 1-hour, 3-hour, and 24-hour ambient standards may not be exceeded more than once in a one-year period. The ambient standards are summarized in the table below (Ref. 8).

Averaging Time	SO_2 National Standard (ppm)	SO_2 State Standard (ppm)
Annual average	0.03	0.02
24 hours	0.14	0.10
3 hours	0.5	--
1 hour	--	0.4 and 0.25[a]

[a] Not to be exceeded more than twice in a consecutive 7-day period.

2. Ambient SO_2 and meteorological monitoring was conducted prior to the operation of the Centralia Plant from December 1969 to 1971. Monitoring data that could be resurrected from this time period indicated that the background level SO_2 measurements at several sites were incomplete and neither maximum 1-hour nor maximum 24-hour concentrations could be resurrected from this project (Ref. 6, p. 1).

3. Ambient SO_2 and meteorological monitoring was conducted after commercial operation of the Centralia Plant commenced in 1971 and was continuous from 1972 through 1974. This monitoring data indicated that the maximum 1-hour concentrations at each of the sites ranged from 0.120 ppm to 0.402 ppm. The latter value, expressed with the same number of significant digits as the standard, equaled Washington's 1-hour standard of 0.4 ppm. Maximum 24-hour concentrations varied from 0.048 ppm to 0.086 ppm (Ref. 6, p. 1). The ambient 24-hour standard is 0.14 ppm. The maximum annual arithmetic mean concentration at the six sites varied from 0.001 ppm at a Tenino site to 0.017 ppm at a downtown Centralia site (Ref. 29, p. 50). Washington's ambient SO_2 annual average standard is 0.020 ppm.

4. Additional ambient SO_2 and meteorological monitoring was conducted from October 1988 through March 1991 at two locations northeast of the Centralia Plant, Crawford Mountain and Skookumchuck Reservoir (Ref. 29, p. 51). These sites were selected because they would possibly record the highest SO_2 levels during stagnant meteorological conditions. They may or may not record the highest SO_2 levels during other meteorological conditions which occur a much larger percentage of the year.

a. Maximum 1-hour concentrations monitored at the Skookumchuck Reservoir site varied from 0.028 ppm to 0.248 ppm. The latter number occurred on two occasions. The Crawford Mountain site maximum 1-hour concentrations varied from 0.058 ppm to 0.500 ppm. The latter reading occurred on August 12, 1990 and exceeded Washington's 1-hour standard. At that time both Centralia Plant boilers were in their normal operating range. No more readings exceeding the standard were recorded through March 1991 when monitoring at these sites ceased (Ref. 29, Appendix K). Therefore, neither a violation of the standard nor compliance with the standard could be demonstrated since monitoring did not occur for a full year after the lone recorded exceedence. A violation of the 1-hour ambient standard exists when there are two exceedences of the standard in a 12-month period. Washington's primary (i.e., human health-based) 1-hour ambient standards are 0.40 ppm (1,065 $\mu g/m^3$) not to be exceeded more than once per year, and 0.25 ppm, not to be exceeded more than twice in seven days (Ref. 8).

b. Maximum 3-hour SO_2 concentrations monitored at the Skookumchuck Reservoir site varied from 0.020 ppm to 0.144 ppm. The Crawford Mountain site recorded 3-hour concentrations from 0.028 ppm to 0.246 ppm (Ref. 29, Appendix K). The secondary (i.e., plant life-based) 3-hour ambient standard is 0.500 ppm (1,300 Φg/m^3) and is not to be exceeded more than once per year (Ref. 9).

c. Annual average SO_2 concentrations varied from 0.001 ppm to 0.007 ppm. The annual ambient standard is 0.02 ppm (53 μg/m^3) in the state of Washington.

5. The Centralia Plant concluded from these ambient monitoring studies that its impact on SO_2 air quality was (Ref. 29, p. 50-51):

a. Given that the Crawford monitoring site location was selected as having the highest predicted potential for plume impact from the Centralia Plant's emissions, far lower ambient levels would be anticipated throughout the remainder of the area.

b. On a monthly and annual basis, none of the monitoring sites near the Centralia Plant were close to violating the air quality standards.

c. The Centralia Plant is located in an area designated as attainment with all state and federal ambient air quality standards. In addition, the entire state of Washington is in attainment of the SO_2 National Ambient Air Quality Standard.

6. SWAPCA concludes from these ambient monitoring studies that ambient SO_2 levels measured near the Centralia Plant have been between 50% and 125% of the ambient 1-hour standard on occasion and up to 50% of the 3-hour standard. Future operation of the Centralia Plant, if no additional controls were to be provided, is likely to result in more frequent high 1-hour SO_2 readings at such locations as Crawford Mountain and Skookumchuck Reservoir where past ambient monitoring has occurred. SWAPCA staff is concerned that the number of high 1-hour readings would increase along with the associated impacts on air quality and plant life, even exceeding those having occurred during the 1988 to 1991 monitoring study, if emissions are not reduced.

7. As emissions are transported away from the Plant, atmospheric chemical and photochemical changes occur, along with physical dispersion in the air and deposition to surfaces. Over time, a portion of the emitted SO_2 will remain gaseous and a portion will be converted to sulfuric acid and sulfate aerosols, or fine particles. The conversion of SO_2 to sulfate (SO_4) aerosol is a non-linear process involving formation of sulfuric acid and subsequent reaction with atmospheric ammonia. The reactions depend on atmospheric conditions including relative humidity. SO_4 aerosol is a component of $PM_{2.5}$ (particles of diameter less than 2.5 μm) and is discussed further in '5.1.2 Ambient Levels of PM_{10} and $PM_{2.5}$. Both gas and aerosol forms of the original SO_2 emissions are removed from the atmosphere by dry and wet deposition, the latter occurs usually by rain or snow. The fate of the Centralia Plant's SO_2 emissions a considerable distance away from its stacks will vary considerably depending on weather conditions (Ref. 29, p. 52; and Ref. 40).

8. Modeled increments to ambient concentrations due to the Centralia Plant were predicted in the 1997 study "An Assessment of the Health Risks Due to Air Emissions from the Centralia Power Plant" by Jonathan Samet et al. of the Johns Hopkins University Department of Epidemiology and Kirk Winges of McCulley Frick & Gilman. In this work, the Centralia Plant was the only source from which emissions were modeled. The model CALPUFF was used with wind field inputs from the model CALMET to generate estimates of increments to pollutant concentrations for a systematic grid of points across the region of concern. Hourly pollutant concentrations were determined for an area within 150 miles of the Plant stretching roughly from Bellingham, Washington to Salem, Oregon. The results from this modeling indicate the following (Ref. 40, App. B):

a. Peak 24-hour SO_2 concentrations of 60 to 65 $\mu g/m^3$ (0.024 ppm) northeast and southwest of the plant are predicted to have occurred based on 1990 data. Similar peak values are also predicted for the year 2000 with no SO_2 emission controls on the plant. The modeled result also assumes an increase in emissions due to increased plant utilization and higher coal sulfur content compared to 1990 (Ref. 29, p. 51-52 and Ref. 40, pp. 45-46 and App. C).

b. Maximum annual average SO_2 concentrations of 4.5 to 5.0 $\mu g/m^3$ (< 0.0019 ppm) north-northeast of the plant are predicted to have occurred based on 1990 data. Annual average concentrations of 5.5 to 6.0 $\mu g/m^3$ (< 0.0023 ppm) are predicted in similar locations for the year 2000 with no SO_2 emission controls on the plant. The modeled result also assumes an increase in emissions due to increased plant utilization and higher coal sulfur content compared to 1990 (Ref. 29, p. 51-52 and Appendix L, p. 42-43).

c. The population-weighted annual average SO_2 concentration over the entire modeling domain is predicted to be 0.81 $\mu g/m^3$ for population levels in the year 2000 and no SO_2 emissions control technology in place at the plant (Ref. 40, p. 48 & Table 6).

d. The modeled SO_2 concentrations are all well below the applicable State and National Ambient Air Quality Standards of 265 $\mu g/m^3$, 24-hour average, and 53 $\mu g/m^3$, annual average.

e. Peak 24-hour SO_4 concentrations of 1.6 to 2.0 $\mu g/m^3$ south-southwest of the plant are predicted for 1990 and forecast year 2000 emissions with no SO_2 emission controls on the plant.

f. Annual average SO_4 concentrations of 0.09 to 0.10 $\mu g/m^3$ northeast and south of the plant are predicted for 1990 and forecast year 2000 emissions without any SO_2 emission controls at the plant.

3.1.3 Human Health Effects of SO_2 and Sulfates

SO_2, a highly water-soluble gas, is removed in the upper airway of the respiratory tract. When present in high concentrations, it can irritate the lungs, lower resistance to respiratory illness, and aggravate existing cardiovascular disease. As a result, EPA classified SO_2 as a criteria pollutant and established National Ambient Air Quality Standards (NAAQS) including 0.50 ppm (1,305 $\mu g/m^3$) 3-hour average. The state of Washington has established State Ambient Air Quality Standards (SAAQS) which are more stringent than the NAAQS, and consist of 0.02 ppm (53 $\mu g/m^3$) annual average, 0.10 ppm (261 $\mu g/m^3$) 24-hour average, and 0.40 ppm (1,045 $\mu g/m^3$) 1-hour average, the daily and hourly standards not to be exceeded more than once per year.

Clinical exposure studies have shown that people with asthma are especially sensitive to SO_2, while studies on healthy volunteers indicate that they are unlikely to be affected at typical ambient concentrations. If asthmatics exercise vigorously during exposure, even for only one to three minutes, they may experience noticeable wheezing and constriction of the bronchial passages at SO_2 concentrations of 0.4 to 0.5 ppm. In some studies these effects have occurred at levels as low as 0.2 ppm with only a few minutes exposure. With rest, the effect usually goes away in one-half hour or less, even if SO_2 exposure continues. These effects can occur when the air quality is well within the primary 24-hour NAAQS of 0.14 ppm. This is attributed to the fact that the symptoms can develop with only a few minutes exposure to elevated SO_2 concentrations. The American Lung Association has strongly recommended that EPA adopt a short term 1-hour health standard to protect against these effects (Ref. 10).

On January 2, 1997, EPA proposed an intervention level program to address the risk presented by 5-minute peak SO_2 concentrations. EPA concluded that because health effects caused by short-term SO_2 peaks tend to be localized problems, the intervention level program is the appropriate approach to address this concern. Guidance from EPA indicates that when the concern level of 0.60 ppm, 5-minute average, has been exceeded in a given area, the State, local authority, or tribe should consider whether or not the situation presents a significant public health risk. EPA expects that development and implementation of any course of corrective action for a given situation should occur expeditiously and efficiently, based on the risk to public health, the source(s) causing the peak episodes, the available options for mitigating high SO_2 concentrations, and other pertinent considerations. If the SO_2 concentration approaches the endangerment level of 2.0 ppm, 5-minute average, the health effects become more pronounced and severe. EPA expects States, local authorities, and tribes to intervene and seek corrective remedies with sources when 5-minute peak concentrations reach the 2.0 ppm endangerment level (62FR209).

Samet et al. of the Johns Hopkins University Department of Epidemiology produced in 1997 a study entitled "An Assessment of the Health Risks Due to Air Emissions from the Centralia Power Plant." The Centralia Plant was the only source from which emissions were modeled to generate hourly and annual pollutant concentrations for a grid of points in a region within 150 miles of the plant stretching roughly from Bellingham, Washington to Salem, Oregon. The health effects assessed in this study arise from exposures to particles, including acidic particles, and SO_2. Some of the SO_2 converts to sulfate (SO_4), a fine aerosol assumed to all be less than 2.5 μm in diameter that will primarily be in the form of ammonium sulfate (Ref. 40, p. 6-7).

Modeled pollutant concentration increments were combined with population data to produce increments in exposure. The population exposure increments were combined with risk coefficients describing the mortality or morbidity associated with the pollutants to characterize the risk from plant emissions. The risk estimates for mortality and morbidity associated with the Centralia Plant should not be construed as actual mortality and morbidity, but may be used for comparing to estimated risks from other air pollution sources (Ref. 29, App. L, p. 58). Health impacts were summarized as follows (see TSD '5.1.2 Particulate Matter, Health Effects for additional findings of study):

a. The risk of premature mortality from the plant is estimated throughout the study area to be 3.3 to 34.6 with no SO_2 emission reduction, depending on the assumptions selected for estimating risk. For King County alone, by using the same methodology, the study projected a mortality risk due to all air pollution of 2,053 based on the difference between the actual annual average PM_{10} concentration of 27.4 $\mu g/m^3$ and 9 $\mu g/m^3$, the Abackground@ level in the least polluted communities of the U.S. (Ref. 40, pp. 63-65).

b. Using rates provided by the National Center for Health Statistics, the study estimated the numbers of emergency room visits and outpatient visits for asthma by county for the year 1990. Visits attributable to Plant operations represent a very small proportion of the total (Ref. 40, pp. 64-65).

c. Emergency room and outpatient facility visits estimated to result from plant emissions range from 70 to 106 with no SO_2 controls in place. This compares with an estimated total of 260,000 asthma-related visits each year in the study area (Ref. 40, p. 7 and Table 18).

d. Exposures to air pollution resulting from Centralia Plant emissions for 5.5 million people residing within a 150-mile radius of the plant were estimated with a state-of-the-art pollution model. Compared to the population's total exposure to air pollution, the Centralia Plant is a minor contributor even without SO_2 controls (Ref. 29, App. L, p. 65).

In their 1992 report "Air Quality Analysis and Related Risk Assessment for the Bonneville Power Administration's Resource Program Environmental Impact Statement", Glantz et al. estimated annual cumulative exposures within an 80 km radius based on 1991 emissions data for the Centralia Plant. For population levels projected for the year 2000, the total cumulative exposure to SO_2 was estimated to be 671,503 person-$\mu g/m^3$. The dispersion model used in this study did not account for chemical conversion of SO_2 to sulfate (Refs. 40 and 41).

Using the total cumulative exposure approach in the BPA report, Samet et al. estimated the impact of only Centralia Plant SO_2 emissions without controls according to the Glantz et al. model to be 20 excess deaths per year and the following annual morbidity effects (Ref. 40, pp. 25-26 & Table 4):

a. 99 instances of lower respiratory effects;
b. 197 cases of bronchitis;
c. 197 instances of coughs; and
d. 177 colds.

Samet et al. state that limitations are evident in the approach used by Glantz et al. noting that its air pollution model fails to account for terrain or chemical reactions that produce secondary aerosols, and its health risk calculations use risk coefficients from older epidemiologic studies.

3.1.4 Visibility Impairment

1. Pursuant to the 1977 Clean Air Act Amendments, the EPA promulgated visibility protection regulations for national parks and wilderness areas that have been designated federal Class I areas. These regulations require the states to develop programs to assure that reasonable progress is made toward the national visibility goal of remedying existing and preventing future visibility impairment (Ref. 21, p. 1-5).

2. The 1990 Clean Air Act Amendments include Section 169A(a) in which Congress declares it a national goal to prevent any future, and remedy any existing, impairment of visibility in mandatory Class I federal areas which results from manmade air pollution.

3. The 1990 Clean Air Act Amendments include Section 169B, which calls for Visibility Transport Regions and Commissions, research, monitoring, assessments, and recommendations leading to regulatory action, on a 7-1/2 year time schedule, to define and implement "reasonable progress towards the national goal of no manmade visibility impairment" in Class I areas (Ref. 15, p. 62).

4. The Clean Air Act states that the ultimate goal of Class I area visibility protection is "no humanly perceptible change in coloration or contrast" (Ref. 13, p. 38).

5. The official U.S. Forest Service policy is to protect visibility as it relates to views only within the Class I area. The Pacific Northwest region of the U.S. Forest Service advocates additional clarity of view from both inside to outside and outside to inside consistent with the definition of integral vista (Ref. 13, p. 35).

6. Primary SO_2 emissions form secondary sulfate aerosols in the atmosphere. These particles then absorb water vapor during transport which scatter light and contribute to regional haze (Ref. 15, p. 34 and Ref. 7, Appendix D, p. 4).

7. Most visibility impairment is associated with secondary aerosols such as sulfates, nitrates, and secondary organics. Therefore, any visibility apportionment scheme must address secondary as well as primary particles (Ref. 21, p. 1-11).

8. The Centralia Plant is located approximately 75 km due west of the southwestern corner of Mount Rainier National Park, a Class I area.

9. The Pacific Northwest Regional Visibility Experiment Using Natural Tracers (PREVENT) study was initiated in 1990 by the National Park Service to determine the sources of visibility reducing aerosols impacting summertime visibility at Mount Rainier and North Cascades National Parks (Ref. 21, p. 1).

10. The Centralia Plant's conclusions from the PREVENT study were:

a. The Centralia Plant contributes to elevated sulfate levels, but urban sources of sulfur are significant and play a larger role than their emission strengths would suggest (Ref. 29, p. 54).

b. The role of sulfate in light extinction may be substantially less than previously thought. Recent work completed as part of project MOHAVE near Grand Canyon National Park suggests that elemental carbon occupies a much larger part of the extinction budget than previously thought. The work of Malm and others suggest that there are significant quantities of carbon in the atmosphere in the Northwest (Ref. 24, p. 12).

c. Total light extinction was never actually measured during the PREVENT study. Since the extinction coefficient is an estimate, any contribution made to it must also be considered an estimate and subject to further measurement and analysis (Ref. 24, p. 14).

d. The largest contributor to visibility reduction can not be determined if the total visibility reduction or extinction was not measured during the PREVENT study. No emissions inventory, no stack or area source sampling was ever attempted during PREVENT. The contribution of sulfur to visibility reduction is based purely on statistical extrapolation of the data and may not be correct (Ref. 24, p. 14).

e. The very nature of the "hits" appear to be somewhat of conjecture and their ultimate impact on visibility reduction is not discussed (Ref. 24, p. 14).

f. The PREVENT study was not able to establish a strong relationship between selenium and Centralia Plant's emissions (Ref. 24, p. 15).

g. The reduction of Centralia Plant's SO_2 emissions by 90% through full scrubbing would reduce Centralia's contribution to regional haze and visibility impairment. However, it is unlikely that even the 90% reduction of SO_2 emissions will result in a perceptible improvement to visitors at Class I areas like Mount Rainier National Park (Ref. 29, p. 53).

h. The PREVENT report's conclusions attributing visibility impairment to Centralia Plant emissions are based on supposition. The Respondent further believes that more study, additional monitoring and analysis are necessary to determine if reduction of Centralia Plant's emissions will result in a perceptible improvement of visibility in the region's Class 1 areas (Ref. 24, p. 17).

i. The agency members of the CDM group reviewed the PREVENT study with the study's authors and concluded that 16% of visibility impairment at Mount Rainier National Park can be attributed to the contribution of sulfates from Centralia Plant's SO_2 emissions (Ref. 29, p. 54).

11. SWAPCA staff has identified the following conclusions from the PREVENT study:

a. The best visibility was found at the North Cascades monitoring site. At Tahoma Woods, the low elevation Mount Rainier site, visual range was somewhat less while at the high elevation Mount Rainier site, Paradise, average visual range was estimated to be the lowest (Ref. 21, p. 3).

b. Sulfur was the single largest contributor to visibility reduction. At Tahoma Woods, a chemical mass balance (CMB) apportioned 78% to 90% of the selenium to coal-fired power plants (Ref. 21, p. 5).

c. Most sulfur episodes at Paradise were associated with air masses that passed over the Centralia Plant. The CMB analysis predicted a coal-fired power plant "hit" four of the six times that back trajectory analysis showed the Centralia Plant impacting Paradise. There were, however, time periods when sulfur at Paradise was not associated with the Centralia Plant (Ref. 21, p. 5).

i. A "hit" indicates only that air which arrived at the receptor site during the monitoring period probably passed over the Centralia Plant sometime during the previous five days. Because emission rates, dispersion and deposition are not taken into account, a hit does not necessarily imply that emissions from the power plant impacted the receptor site (Ref. 21, p. 10-2).

ii. The highest sulfur concentration episodes at Paradise and Tahoma Woods are almost always associated with "hits" from the Centralia Plant (Ref. 21, p. 10-2).

d. At Tahoma Woods, the relationship between back trajectories that pass over Centralia Plant and elevated sulfur was not as close as at Paradise. Sulfur was more uniformly elevated at Tahoma Woods and did not show the same strong episodic nature it did at Paradise. However, the time period corresponding to the largest sulfur episode at Paradise was also the largest sulfur episode at Tahoma Woods. As at Paradise, the CMB analysis predicted the largest relative coal-fired power plant impact when the back trajectories passed over the Centralia Plant (Ref. 21, p. 6).

e. At Paradise the correlation between back trajectories that pass over Centralia Plant and elevated sulfur suggest that the Centralia Plant may be a major contributor to elevated sulfur levels at Paradise (Ref. 21, p. 8).

f. The source apportionment analysis showed that sulfur was statistically linked to coal-fired power plant emissions and urban emissions. The trajectory analysis combined with spatial trends in sulfur concentrations tended to confirm an urban transportation (Seattle-Tacoma area) and a coal-fired power plant (Centralia Plant) influence on sulfur concentrations at Mount Rainier National Park (Ref. 21, p. 7).

g. The quantitative apportionment of secondary visibility reducing aerosols to sources using source-receptor techniques is difficult because of complex atmospheric transport, dispersion, and chemistry. However, strong source-receptor trends do emerge. Sources in addition to the Centralia Plant are contributing to elevated sulfur at both the Tahoma Woods and Paradise monitoring sites. Urban sources of sulfur apparently are significant and play a larger role than their emission strengths would suggest. This is especially true at the Tahoma Woods location. However, at Paradise the high degree of correlation between back trajectories that pass over Centralia Plant and elevated sulfur episodes, the correlation between sulfur and selenium, and the association between the relative coal-fired power plant source strength predicted by CMB analysis all suggest that Centralia Power Plant is a significant contributor to sulfate levels at that site (Ref. 21, p. 10).

h. Even though the SO_2 emission inventory suggested that the Centralia Plant is the single largest SO_2 emitter, it does not seem to be the largest contributor to sulfates at Tahoma Woods. At Paradise it may be a large contributor, but so are other sources. If all the selenium is from the Centralia Plant, and it probably is not, then the regressions suggest that at Tahoma Woods only about 10% of the sulfur could be attributed to the power plant, while at Paradise its contribution could be between 30% and 40% (Ref. 21, pp. 8-18 and 8-19).

i. Even though sulfates account for only 20-30% of the fine particulate mass, it is estimated that they are over 50% of the non-Rayleigh extinction budget (Ref. 21, p. 6-36).

j. It is conceivable that removal of a fraction of "optically active" sulfur could disproportionally reduce sulfate scattering (Ref. 21, p. 1-10).

k. The dominant spatial patterns associated with elemental sulfur concentrations indicate that the Centralia Plant is probably not the only important source of sulfur in the region. The spatial pattern in the sulfur concentrations strongly suggest that other sources of sulfur in the Seattle-Tacoma urban area influence the sulfur concentrations in western Washington also (Ref. 21, p. 11-52).

l. The empirical orthogonal function (EOF) pattern indicates that emissions from Centralia Plant may often become a part of the Seattle-Tacoma urban air mass and that sources of sulfur in the urban area may be individually or collectively as important as the Centralia Plant in influencing the sulfur concentrations in the region (Ref. 21, p. 11-7).

12. Most of the air masses of concern seem to enter Mount Rainier National Park from the west and northwest; thus, the location of the Paradise site may underestimate maximum pollutant exposures in the park. Locating monitoring stations at Paradise is understandable because of favorable access considerations, but it is also likely that this site is not optimal with respect to measuring maximum pollutant concentrations within the Mount Rainier National Park (Ref. 4, p. 124).

13. In Mount Rainier National Park, modeling indicates that up to one-third of the sulfate can be attributed to the Centralia Plant (Ref. 23, p. 1).

14. Acid deposition control will improve average visibility and allow for increased enjoyment of scenic vistas across the Nation (Ref. 15, p. 2).

a. Sulfur compounds from a wide variety of sources have been confirmed as major contributors to regional haze in eastern North America and to the distortion of visibility (Ref. 15, p. 4).

b. Sulfur and nitrogen compounds both contribute to regional haze, visibility degradation and disturbance of the biochemical cycling of other nutrients and metals in ecosystems (Ref. 15, p. 3).

15. Modeling indicates that sulfate concentrations from Centralia Plant SO_2 emissions are sufficient to contribute to perceptible changes in visibility at Mount Rainier National Park on a number of days. The number of days varies from a low of 19 out of a possible 139 days when the sky is clear or partly cloudy to a high of 41 of the 139 "clear" days, or 29% of the time. When visibility change is expressed in "deciviews", the model finds that 36 "clear" days would experience a deciview change of one or greater in at least one of the Class I areas modeled. A change of one or more deciview would be perceptible to the human eye and roughly corresponds to a 10% change in the extinction coefficient (b_{ext}) which is directly related to visual range (Ref. 18, p. 10; 15-16).

16. Visibility is an important feature of all national parks, wilderness areas and scenic areas because it impacts tourism. For instance, the Columbia River Gorge National Scenic Area has established the following "key viewing areas" in recognition of the importance of these areas to the visitor's experience: Historic Columbia River Highway, Crown Point, Highway I-84 (including rest stops), State Route 14, Beacon Rock State Park, Highway 35 at Panorama Point, Cape Horn, Highway 197, Dog Mountain Trail, Cook Underwood Road, Rowena Plateau, Railroads on both sides of the Columbia River, Sciorsus Park, Portland Women's Forum State Park, Seven Mile Hill, Bridal Veil State Park, Larch Mountain, Rooster Rock State Park, Bonneville Dam Visitor Center and Columbia River (Ref. 11).

17. Mount Rainier National Park experienced the following number of recreational visits in recent years:

Year	Number of Recreational Visits
1991	1,549,000
1992	1,522,100
1993	1,365,200

18. In 1985 Mount Rainier National Park visitors spent over $13 million on goods and services in the vicinity of the Park and nearly $37 million in the state of Washington. Although the main users of the park are Washington State residents (62%), out-of-state visitors (38%) are the main source of income to the locality bringing in 67% of park visitor expenditures (Ref. 25).

19. The 1992 Report To Congress on the National Acid Precipitation Program concluded that adequate information exists to justify new air rules on visibility and that targeting only single-point sources may not be the best approach, since a wide variety of sources can contribute to the regional haze that distorts visibility (Ref. 15, p. 62).

20. Air quality monitoring data collected by the U.S. Forest Service in the Columbia River Gorge Scenic Area during a portion of 1994 suggested coal combustion emissions were reaching the Gorge Scenic Area but at lower levels than forest fire sources (Ref. 17).

21. As noted in the Review of the Washington State Visibility Protection State Implementation Plan, the contribution of sulfate to light extinction in the Cascades on "dirty days", defined to be when the scattering coefficient b_{scat} exceeds 50, is the largest portion of any visibility impairing pollutant. This result is duplicated whether the standard method of partial contribution analysis is used which assumes sulfur is converted primarily to ammonium sulfate ($(NH_4)_2SO_4$), or an alternative method used by Halstead Harrison of the University of Washington is employed. The alternative method of data regression assumes the dominant aerosol form of sulfur is ammonium bisulfate (NH_4HSO_4), due to the influence of marine aerosols in the Pacific Northwest (Ref. 30, App. B p.16-19).

3.1.5 Emission Limit Violations

An exceedence of the 1-hour state SO_2 emission standard of 1000 ppm, dry at 7% O_2, was measured in the stack of Centralia Unit #2 during a source test conducted on October 1, 1987. The average of the three 20-minute test runs was 1232 ppm, dry at 7% O_2. The first of the three EPA Method 6 test runs began at 10:32 and the third run ended at 12:32 PDT, during which period 60 minutes of sampling occurred. At the time of this exceedence, the Centralia Plant was operating under a variance to the 1-hour averaging period that allowed compliance with the 1,000 ppm standard to be demonstrated based on a weekly average. No violation of the SO_2 standard occurred because the emission concentration was averaged over a period of one week.

The 1-hour state SO_2 emission standard of 1000 ppm, dry at 7% O_2 was exceeded for two consecutive hours on January 5, 1993 in the stack of Unit #1 at Centralia Plant. The single highest 1-hour average was 1064 ppm, dry at 7% O_2 which occurred from 16:00 to 16:59 PST. The exceedence resulted from delayed notification by CMC of high-sulfur coal delivered directly to the Plant's fuel silos. Operators took immediate action to minimize emissions when the presence of high-sulfur coal was known, but could not remove coal already delivered to the silos. This exceedence constituted one exceedence day. As provided in SWAPCA 90-934E, a violation is not triggered until two exceedence days are recorded in one month.

An exceedence of the 1-hour state SO_2 emission standard of 1000 ppm, dry at 7% O_2, occurred at Centralia Unit #2 for three consecutive 1-hour periods on June 17, 1997. The single highest 1-hour average was 1045 ppm, dry at 7% O_2 which occurred from 01:00 to 01:59 PDT. As provided in SWAPCA 90-934E, a violation is not triggered until two exceedence days are recorded in a month. This three hour exceedence constitutes one exceedence day. The exceedence was the result of high sulfur coal in the storage piles being fed into the coal silos during Unit #2 startup. Normally coal is supplied directly from the mine and sulfur analysis is performed on-line. During startup of Unit #2 coal was supplied from a storage pile where the sulfur content was not readily known. Because of the high SO_2 levels indicated in the control room, the operators began to introduce fuel oil into the boiler and reduce the coal flow. This action resulted in lowering the SO_2 stack concentration below the 1000 ppm limit where emissions remained throughout the rest of the startup.

Coal mined from CMC is projected to have more widely varying sulfur content in the future. As cost saving measures are enacted to keep the coal supply from CMC economical into the 21st century, the sulfur content of coal sent to the Plant will increase resulting in less margin below the 1000 ppm hourly standard. Future exceedences of the 1000 ppm hourly standard are more likely the longer the Plant operates without control technology to reduce SO_2 emissions. However, coal blending to minimize sulfur content will continue through installation and commencement of SO_2 emissions controls.

3.1.6 Odor and Other Nuisance Issues

Odor. No odor complaints have been reported by the public in regard to emissions of SO_2 at the Centralia Plant. This is evidenced by a review of the plant files at SWAPCA.

Health Complaints. Over the past several years, there was one health related complaint received by SWAPCA on November 10, 1993. The complainant alleged that high sulfur coal piles were spontaneously combusting releasing sulfur and soot into the air. In addition, this person was aware that soot cleaning was performed at night at the Centralia Plant which releases soot into the air that impacts this person. This person reportedly has gone to the hospital on several occasions because of respiratory problems.

Other nuisance complaints. A few nuisance complaints were recorded by SWAPCA in the early years of plant operation with respect to fine particulate matter but were not directly associated with SO_2.

3.1.7 Acid Deposition

1. Acid deposition is dominated by long-range transport of air pollutants. SO_2 may travel hundreds or thousands of miles before it is deposited into local ecosystems (Ref. 7, Appendix A, p. 3).

2. RACT determinations in other states are to be considered by local air authorities (Ref. 1, RCW 70.94.154(5)).

3. The King Plant RACT decision in Minnesota made the following determinations:
a. The SO_2 emissions from the King Plant contribute to the problem of sulfur deposition in other areas of the continent in the same manner that distant emissions contribute substantially to the sulfur deposition problem in Minnesota (Ref. 7, Appendix A, p. 4).
b. No acidified lakes exist in Minnesota. However, lakes with low acid neutralizing capacity have been identified; 200 are critically sensitive. These lakes are usually small, less than 100 acres (Ref. 7, Appendix A, p. 4).
c. The King Plant's interim SO_2 RACT annual average emission limit of 1.8 lb/MBtu was lowered to 1.6 lb/MBtu at the conclusion of the hearing. The King Plant owners indicated that the power plant would need to operate near a target of 1.4 lb/MBtu in order to comply with the 1.6 lb/MBtu emission limit.

4. An Acid Rain Report prepared for Washington's State Legislature in 1986 made the following determinations:
a. Forests in Washington appear to be under little threat of damage from acid precipitation (Ref. 7, Appendix C, ES).
b. Aquatic organisms and waterfowl populations inhabiting lake and river systems in the state were not currently in danger of disruption (Ref. 7, Appendix C, ES).
c. The presence of sensitive receptors such as alpine lakes and forests in the Cascades dictates a need for continued monitoring (Ref. 7, Appendix C, ES).
d. With respect to the data that is currently available, the need to adopt more stringent regulations solely to address acidic precursors was not demonstrated (Ref. 7, Appendix C, ES).
e. Considerably more information is needed before the detrimental effects of acid deposition can be adequately assessed (Ref. 7, Appendix C, ES).

5. Acid deposition effects in Washington were monitored and evaluated from 1984 to 1991. In general, the findings indicated that some lakes in the Cascades are sensitive to acidic deposition but no long-term effects of acidic deposition have been documented (Ref. 15, pp. 58 and 84 and Ref. 16, p. 35).

6. The closure of the ASARCO smelter appears to have had little effect on acid deposition in the Cascades near Class I areas (Ref. 27, p. 8).

7. There is strong basis for concern that the long-term integrity of lakes in the Cascades could be affected if atmospheric deposition contains pollutants (Ref. 13, p. 19; Ref. 15, pp. 58 and 84; and Ref. 16, p. 35).

8. It is generally accepted that surface waters with chemical characteristics like those in the Cascades are indicative of extremely sensitive systems, but as yet these lakes do not exhibit any signs of acidification from atmospheric deposition (Ref. 13, p. 24; Ref. 15, pp. 58 and 84; and Ref. 16, p. 35).

9. Recent studies indicate that fresh water ecosystems in the vicinity of Mount Rainier National Park can only sustain a sulfur loading of 3 kg/ha/yr. Modeling of receptors near Lake Allen and Eunice Lake on the west side of Mount Rainier National Park are at 0.85 kg/ha/yr. Based on these modeling results, the Centralia Plant contributes almost 30% of the maximum sulfur loading that these lakes can sustain. In addition, the wet component of the sulfur deposition may be underestimated by the modeling since precipitation at higher elevations is under-represented. While the Centralia Plant does not by itself damage these fresh water systems, it does contribute very significantly to the deposition in the area (Ref. 18, p. 16).

10. For protection of sensitive lakes and streams in Mount Rainier National Park and North Cascades National Park, an interim nonmarine sulfur deposition guideline of 20 meq/m^2/yr (about 3 kg S/ha/yr; 9 kg SO_4/ha/yr) is recommended. This recommendation for maximum sulfur loading to these two parks is predicated on the following:

a. The recommended sulfur loading will not necessarily protect all sensitive aquatic resources at all times. This recommended loading is adequate for protecting at least 95% of the resources from chronic acidification, but it may not be adequate for long-term protection of the most sensitive resources.

b. The recommended sulfur loading may not protect aquatic resources from episodic acidification from either sulfur or nitrogen deposition. Episodic acidification will precede chronic acidification in many systems, particularly in view of the importance of snow to the hydrologic budgets of the alpine lakes.

c. The recommended sulfur loading does not address possible accumulation of nitrates in low temperature lakes that remain ice covered for most of the year (Ref. 4, p. ix).

11. The closest National Atmospheric Deposition Program/National Trends Network (NADP/NTN) site to the Centralia Plant is located 25 km from Mount Rainier National Park near La Grande in the University of Washington Pack Forest. Wet deposition chemistry data from measurements at La Grande, Washington were as follows (Ref. 4, Table 22):

Year	SO_4	(Sea salt-corrected SO_4)
1990	4.22 kg/ha	10.1 ueq/L
1991	4.97 kg/ha	10.0 ueq/L
1992	5.16 kg/ha	9.8 ueq/L

12. The total amount of sulfur deposition in the vicinity of the Centralia Plant and surrounding area was modeled in 1984 to be about 20 kilograms per hectare (kg/ha). Wet sulfur deposition was estimated to be 10 kg/ha (Ref. 19, pp. 45 and 46).

13. The La Grande, Washington NADP/NTN site has measured sulfate concentrations significantly greater than those observed at the other parks in the Pacific Northwest. The greater concentrations of sulfate near Mount Rainier National Park may reflect its proximity to emission sources of SO_2 in western Washington. In particular, the single largest emission source in the Pacific Northwest, the Centralia Plant, is located about 75 km west of Mount Rainier National Park and 50 km west of the

NADP/NTN monitoring site. The contribution of the acid anions, sulfate and nitrate, to the precipitation at La Grande causes the precipitation to be more acidic (pH about 5.0) than what was observed at other sites in western Washington and Oregon where the pH is near 5.4 (Ref. 4, p. 102).

14. Fog and cloud chemistry were measured at Sunrise and Paradise in Mount Rainier National Park and Burley Mountain to the south of Mount Rainier National Park in the winter of 1987-1988. These three sites exhibited the highest concentrations of sulfate, nitrate, ammonium and hydrogen measured among the twelve stations in the study. Cloudwater pH values less than 4 were commonly measured at Mount Rainier National Park (Ref. 4, p. 105).

15. Regional cloudwater chemistry in western Washington indicates anthropogenic enhancement of ionic concentrations in clouds collected downwind from developed areas in the Puget Sound region. Low elevation radiation fogwater composition was generally less acidic than mountain clouds. In general the mountain clouds in the Olympic Peninsula and North Cascades were less acidic than mountain clouds southeast of the greater-Seattle area (Ref. 20).

16. In the area north of the central Cascades, modeling predicts an average rainfall Ph of just above 4.7 to about 5.0. A pH of 5.6 would represent the natural background of rain in equilibrium with the carbon dioxide in the air and no background of sulfur dioxide present. Rainfall pH ranges from 4.1 to 4.4 occur over much of the eastern United States. In general, a rainfall pH below 4.7 is necessary for acidification of lakes to be found (Ref. 19, p. 47).

17. Nonmarine sulfate and hydrogen ion concentrations in precipitation for at least portions of the Washington Cascades are slightly above background concentrations (background concentrations are approximated by precipitation measured on the west side of the Olympic National Park) and are a cause for concern in Mount Rainier National Park and North Cascades National Park (Ref. 4, p. vii).

18. Although the measurements made during the PREVENT study were not explicitly designed for purposes of estimating aerosol acidity, a method for estimating acidity utilizing measurements made at the three major receptor sites is available (Ref. 21, p. 7-1). At all three sites, there were a few time periods when the hydrogen/sulfur (H/S) ratios are suggestive of acidic aerosols (Ref. 21, p. 7-7).

19. There is no evidence of a general, widespread decline of forest tree species in the U.S. caused by acidic deposition. However, in recent field studies, acidic deposition has been firmly implicated as a causal factor in northeastern high-elevation red spruce decline (Ref. 15, Executive Summary and Ref. 14, p. 18-166).

20. There is no case of forest decline in the United States in which acidic deposition is known to be a predominant cause. Only in cases where forests are frequently exposed to highly acidic fog or cloudwater is there evidence that acidic deposition is a significant contributing factor to observed forest health problems (Ref. 14, p. 16-156).

21. In Europe and North America, it is now widely recognized that the direct adverse effects of ambient levels of sulfur and nitrogen oxides on forest health are limited, generally subtle, and complex (Ref. 15, p. 72).

22. In Europe, most researchers believe that the risks facing forests are enough to justify efforts to reduce air pollution (Ref. 15, p. 72).

23. The possibility of long term (several decades) adverse effects of acidic deposition on some soils appears realistic. Sulfate deposition increases leaching losses of nutrient cations from many different forest soils and over the long term may reduce the fertility of soils with low buffering capacity or low mineral weathering rate (Ref. 14, p. 16-156).

24. Air pollutants posing a significant threat to terrestrial resources in Mount Rainier National Park include ozone, and potentially, acidic deposition in cloudwater or fog. Ozone values above 60-80 ppb can be assumed to effect many plant species. Acidic fog (less than pH 4.0) due primarily to sulfate, can potentially harm vegetation in Mount Rainier National Park, although data on exposure and dose-response functions for plants are not adequate to assess the current risk (Ref. 4, p. 121).

25. The snow chemistry at Summit Lake in the Clearwater Wilderness Area was slightly acidic with a pH ranging from 5.34 to 5.38. The data from the lake shows it to be an extremely poorly buffered lake with virtually no neutralization capacity. Most of the SO_4 enters Summit Lake from either rain/dry deposition or from the watershed. Concentrations of SO_4 and NO_3 in the snow were low. It is not possible to determine the origin of the sulfate in the lake, but given the lake's proximity to urban areas it seems likely that some or all of the sulfate is from atmospheric deposition (Ref. 22).

26. In 1983 the measured concentration of sulfate in snow increased as one moved north from Crater Lake National Park. It peaked at Mount Rainier National Park and then decreased with further movement north to the North Cascades National Park (Ref. 4, p. 13).

27. The total wet deposition in the vicinity of Stevens Pass was estimated in 1986 to be 0.05 $eq/m^2/yr$. It was predicted to drop to about 0.04 $eq/m^2/yr$ in 1999. Researchers from the National Swedish Protection Board have suggested a standard of 0.03 $eq/m^2/yr$ to maintain most surface waters in a healthy state and 0.02 $eq/m^2/yr$ for sensitive waters (Ref. 19, p. 47).

28. Weyerhaeuser Company is funding a five-year study on the acid-base chemistry of two lakes in the Goats Rocks Wilderness Area located southeast of the Mount Rainier National Park and a companion study of snow sampling at six sites in the Washington Cascades. Lake sampling was initiated in August 1993 and snow sampling began in April 1994. One of the snow sampling sites is located at Paradise in the Mount Rainier National Park (Ref. 4, p. 37).

29. In Mount Rainier National Park, modeling indicates that up to one-third of the sulfate can be attributed to the Centralia Plant (Ref. 23, p. 1).

30. The total value of the resources damaged from anthropogenic acid deposition represents less than one percent of the total value of the yield from each of those resources. Like the physical damages, the primary economic damages are predicted to be in the wilderness area in the Alps-Glacier Peak region (Ref. 7, Appendix C, p. 147).

31. The values developed by the EPA as PSD increments were not selected by any existing information on concentration limits needed to protect specific resource values. It is therefore

possible that a Class I wilderness area could be impacted without exceeding the increments; for example:

a. The particulate increment does not prevent visibility impairment.

b. There is no PSD increment for ozone although the national ozone standard of 120 parts per billion exceeds the level of known adverse impacts to vegetation (Ref. 13, p. 4).

32. A variety of metals, including galvanized steel, are usually covered by alkaline corrosion product layers and thus are subject to increased corrosion by acidic deposition. Extensive research conducted world-wide has demonstrated that iron, copper and aluminum products are subject to increased corrosion due to air pollution, in particular SO_2 (Ref. 14, p. 19-3).

33. It has been estimated that wet and dry acidic deposition accounts for 31-78 percent of the dissolution of galvanized steel and copper in outdoor exposures. Metal dissolution rates in urban areas in the northeastern United States are about three times the rural rates (Ref. 15, p. 7).

34. Acidic deposition plays an important role in many forms of irreversible stone decay - for example: cracking and spalling, dissolution and discoloration. The shape of the structure influences the rate of stone decay and this rate has been quantified in a few cases (Ref. 15, p. 7).

3.1.8 Other Environmental Effects

Thresholds for direct foliar injury to plants from 1-hour exposures to SO_2 range between 0.50 and 2.5 ppm (500 and 2500 parts per billion - ppb) for sensitive species. Long-term thresholds have proven more difficult to estimate. There is some evidence that annual average concentrations as low as 0.01 to 0.02 ppm (10 to 20 ppb), together with occasional peaks of 0.04 to 0.08 ppm (40 to 80 ppb), can reduce tree growth (Ref. 12).

Slight injury is experienced by Douglas-fir trees at SO_2 levels above 0.065 ppm (65 ppb) (Ref. 13, p. 15).

Douglas-fir, grand fir and western hemlock are considered to have an "intermediate" sensitivity to acute damage by SO_2 when a three tier scale consisting of sensitive, intermediate and tolerant species is used (Ref. 14, Table 18-3, p. 18-32).

To maximize protection of all plant species in a wilderness area or national park, maximum SO_2 concentrations are recommended to not exceed 0.040 to 0.050 ppm (40 to 50 parts per billion), and annual average SO_2 should not exceed 0.008 to 0.012 ppm (8 to 12 parts per billion) (Ref. 13, p. 15).

Lichens and bryophytes are known to be especially sensitive receptors for air pollution.

a. Lichens and bryophytes play an important role in subalpine and alpine areas such as those that exist in the Cascades by acting as food sources and cover.

b. There is little information on the sensitivity of lichens and bryophytes in the Pacific Northwest to air pollution.

c. The taxonomy and distribution of lichens in this region are poorly known.

d. Lichens fall into three classes of sensitivity to SO_2 air pollution: sensitive - 0.005-0.015 ppm; intermediate - 0.010-0.035 ppm; and tolerant - >0.030 ppm (Ref. 13, p. 17).

The sensitivity of selected lichen species (i.e., plant life) to SO_2 levels below the 40 Φg/m^3 concentration used as the limit for sensitive species is:

a. 0.002 ppm (5 Φg/m^3) - *Lobaria pulmonaria* is absent from areas with concentrations higher than this level. However, another author found this species in areas with 13-26 Φg/m^3.

b. 0.003 to 0.004 ppm (8 to 10 Φg/m^3) - Several lichen species are listed as experiencing some damage at this level or above.

c. 0.005 to 0.006 ppm (13 to 15 Φg/m^3) - Some species of lichens are damaged or killed by mean annual levels of SO_2 as low as 0.005 ppm (13 Φg/m^3). Several authors have found losses in reproductive capacity at levels as low as 13 Φg/m^3. These species are listed in the document.

d. 0.01 to 0.011 ppm (25 to 30 Φg/m^3) - One author found statistically significant decreases in total lichen cover, species richness, and index of atmospheric purity values over a gradient of 23 to 40 Φg/m^3 annual mean SO_2, which indicates that at least some damage to the lichen vegetation occurs at levels as low as about 30 Φg/m^3 (Ref. 13, p. 64).

3.2 Availability of Additional SO_2 Controls

This section will determine whether or not additional controls are technically available. Later sections will determine which of these control technologies offer the lowest emission limit and which are economically feasible, the other components of RACT. The emission control options presented in this section are influenced by the CDM Target Solution, and therefore a traditional RACT analysis, as with the other pollutants of concern, is not represented.

"Reasonably available" can be defined as any of the following:

(a) A dictionary definition concludes that "reasonably available" means something that is not "excessive" considering existing technology and cost.

(b) A quantified benefit cost analysis is another possible definition. With this definition, it would be necessary to numerically demonstrate that the benefits of further SO_2 reductions outweigh the costs.

(c) Another definition is contained in a determination made in the Federal Clean Air Act of 1990. Conclusions were made in these deliberations that strategies and technologies for the control of precursors to acid deposition are currently in existence and economically feasible.

(d) A fourth definition is that a control technology represents RACT if it is commercially available and its costs are similar to those paid by similar sources (Ref. 26, p. 2-6)

The Minnesota RACT decision stated that the initial concept of RACT was meant to be flexible and represent a prudent imposition of an obligation on the utility, considering both available technology and cost (Ref. 7, Appendix A, p. 9).

To determine whether a control technology is reasonably available, the definition requires that consideration be given to the technological and economic feasibility. The operative word is "feasible". In deciding the feasibility of a project, its cost is a potent and determining factor to be considered (Ref. 7, Appendix A, p. 10).

The Environmental Protection Agency (EPA) has determined that RACT, at least in nonattainment areas, is not limited to "off the shelf" control alternatives; it has a technology-forcing aspect to it, and may vary among different facilities in the same source category depending on the feasibility of implementing particular control technologies at each location (Ref. 26, p. 2-1).

The Washington Department of Ecology has adopted the policy that available control technologies include those which are:

a. Used by others for similar sources;
b. Off the shelf; and
c. Available to buy or license (Ref. 5).

A control technology may not be feasible if the resulting environmental impacts cannot be mitigated. In many instances, however, control technologies have known energy penalties and adverse effects on other media, but such effects and the cost of their mitigation are also known and have been borne by owners of existing sources. Such well-established adverse effects and their costs are normal and assumed to be reasonable and should not, in most cases, justify excluding the use of the control technology (Ref. 26, p. 2-3).

Respondent's contractor Sargent & Lundy screened a set of 83 potential SO_2 control technologies in 1994 using fatal flaw criteria to reach a first level of evaluation for the Centralia Plant. Among the fatal flaw criteria were (Ref. 29, App. D):

a. The technology should be commercially available.
b. The developmental status of the technology should be beyond the pilot stage.
c. The operating experience for this technology should be with U.S. coal fired flue gas.
d. The power train should be unaffected by this technology.
e. The technology should be flexible to the source of fuel and fuel parameters.

A set of 74 control technologies was screened in 1997 for technical feasibility to be used at the Centralia Plant. The list was then reduced to 7 SO_2 control alternatives by screening out those emission reduction options that were considered unsuitable for further evaluation. The criteria considered in eliminating emission reduction options from further evaluation were the following (Ref. 29, p. 15):

a. The option does not provide emissions control as good as what is currently in place or voluntarily agreed to put in place.
b. The technology is technically infeasible, i.e., it is not commercially available for use on the flue gases of coal-fired boilers.
c. The option would tend to increase the emission rates of more contaminants of concern than it reduces, or the emissions reduction option will increase emissions of toxic air pollutants above their respective Acceptable Source Impact Level.
d. The option would present a public and/or worker safety problem.
e. The option would force a change in product type or quality that would cause a significant reduction in product marketability.
f. The option costs more and/or is not as effective as an option retained for evaluation.

The SO_2 control technologies determined to be available are listed in order from least resultant emissions to highest emissions (i.e., top down approach). For comparison sake, two technologies are included in this analysis that do not achieve the CDM Target Solution.

a. <u>Natural Gas Conversion - Both Units</u>

Natural gas burners would be installed in each of the current coal burner locations to convert both units to 100% natural gas. Conversion would require a new burner management system, boiler implosion controls, and construction of a gas pipeline of about 3 miles in length equipped with pressure reduction stations. At full load, the Centralia Plant would use 25% of the area's natural gas transmission pipeline capacity (Ref. 29, p. 26). The cost of the natural gas fuel is about $2.00/MBtu delivered. Natural gas conversion would receive no fuel tax exemptions enacted by HSB 1257.

b. <u>Full Scrubbing - Limestone Forced Oxidation (LSFO)</u>

Flue gas desulfurization (FGD) by wet limestone forced oxidation is the basis for the CDM Target Solution. A ground limestone and water slurry is sprayed inside absorber vessels to absorb the SO_2 from the flue gas at an overall removal rate of 90%. CMC coal would continue to be burned, so tax exemptions would be available for this option.

(i) The reliability of LSFO systems on utility boilers has been demonstrated. Those utilities that installed scrubbers to comply with the Acid Rain Program Phase I requirements overwhelmingly selected LSFO. It is commercially proven at module sizes that would allow a single absorber for each Centralia Plant unit (Ref. 29, p. 26).

(ii) Approximately 170 flue gas desulfurization (FGD) units (approximately 11,000 MW) were installed between 1970 and 1985. Thus, a substantial amount of experience has been accumulated with this control technology (Ref. 7, Appendix E, pp. 25-131 and 25-135).

(iii) In Acid Rain Program Phase I emission reductions, approximately 50% of the FGD units installed included no spare absorber capacity. Overseas markets use single absorber modules. A study by the North American Electric Reliability Council covering operations from 1986 to 1989 showed that the equivalent forced outage rate for units with no spare absorber modules was 0.68% compared to 0.26% for units with spare absorbers (Ref. 29, App. D).

(iv) Approximately 36 FGD power plant retrofits (i.e., wet limestone/lime) have been installed, including PacifiCorp's Jim Bridger Units 1-3, Wyodak 1 and Naughton 3 (Ref. 7, Appendix E, p. 25-137).

(v) PacifiCorp operates a wet LSFO full scrubbing system at its Hunter Unit 3 plant, and wet lime systems at Hunter/Huntington.

c. <u>Full Scrubbing - Ammonium Sulfate Forced Oxidation (ASFO)</u>

An alternative full scrubbing system, ammonium sulfate forced oxidation uses anhydrous ammonia which is sprayed inside absorber vessels to absorb the SO_2 from the flue gas at an overall removal rate of 90%. ASFO creates ammonium sulfate which is concentrated and processed to obtain ammonium sulfate which can be commercially sold for fertilizer. CMC coal would continue to be burned, so tax exemptions would be available for this option.

(i) The scrubbing reagent ammonia is readily available but its cost is typically more volatile than the cost of limestone employed in LSFO technology.

(ii) ASFO technology has only been applied to one 300 MW system in Great Plains, ND. Ammonia slip from this system is minimal due to its low operating pH and use of in-situ forced oxidation resulting in no visible plume. The Great Plains application is not an electric utility boiler which makes comparisons with the Centralia Plant difficult due to such factors as size of the unit and presence of chloride in coal burned at Centralia Plant. However, the low pH of the Great Plains system prescrubber allows acid gases such as hydrogen chloride to be safely absorbed without forming fumes with ammonia.

(iii) The by-product ammonium sulfate ($(NH_4)_2SO_4$) generated from the FGD process compares favorably with all other grades of $(NH_4)_2SO_4$ in terms of purity as well as trace element constituents. Use of this by-product in granulated form is compatible with other granulated fertilizers.

(iv) Use of $(NH_4)_2SO_4$ in the U.S. is estimated to be about 2 million tons per year, providing an available market for the by-product formed by this FGD process (Ref. 29, App. D).

d. <u>Full Scrubbing - Lime Spray Dryer and All External Coal</u>

Installation of a lime spray dryer (LSD) in the ducts between the existing ESPs would remove 75% of the SO_2 from the flue gas. When coupled with all external, low-sulfur coal, this option would achieve the emission level of the CDM Target Solution. However, since CMC coal would no longer be used, this option would receive no coal sales tax exemptions enacted by HSB 1257.

(i) The current generation of spray dryer FGD processes use lime. Sodium carbonate is more reactive than lime but is more expensive and requires special disposal techniques for the by-products. Limestone, although less expensive than lime, is unsuccessful in this process due to low reactivity (Ref. 29, App. D, p. 1).

(ii) Lime spray dryer FGD uses lime slurry, or calcium hydroxide, to absorb SO_2 in well-distributed atomized slurry droplets. Much development work has achieved uniform distribution and thorough mixing of the flue gas and atomized lime slurry to ensure high SO_2 collection rates. The liquid-phase reaction forms calcium sulfite and calcium sulfate which remain as dry particulate matter in the gas stream after the heat of the flue gas evaporates the water from the droplets. Remaining particulate matter is collected in the downstream ESP, but no significant additional SO_2 removal occurs there.

(iii) PacifiCorp operates a dry lime spray dryer followed by an ESP at its Wyodak Plant. Experience shows SO_2 removal is limited to about 75% to 80% with the ESP following the lime spray dryer.

(iv) Sargent & Lundy report the largest commercial LSD unit is about 230 MW, requiring at least three modules per unit at Centralia Plant (Ref. 29, App. D).

(v) Lime spray dryer technology is proven on utility boilers and offers certain advantages over wet limestone systems. These advantages include lower energy and water requirements, reduced slurry pumping requirements, flue gas discharge temperature above saturation, no potential for gypsum scale, use of carbon steel instead of alloy steel construction, and continued use of existing stacks in retrofit situations.

(vi) Centralia Plant is currently receiving up to 22% of its fuel supply as external coal (Ref. 29).

(vii) Respondent believes there is a cost and reliability risk associated with being a captive customer of the railroads which exposes the Respondent to unilateral cost escalations and potential interruptions in supply due to rail traffic approaching capacity (Ref. 29, p. 34).

(viii) Rail line capacity in the region is near maximum which would create some uncertainty in coal supply for the Plant (Ref. 29, p. 34).

(ix) The size of Centralia Plant's coal inventory is not currently limited by either state or federal regulations. The current targeted stockpile size of 800,000 tons is determined by operational and economic considerations. The stockpile has been as high as 2,629,000 tons in 1982 (Ref. 6, p-16).

e. <u>Full Scrubbing - Lime Spray Dryer with New Baghouse</u>

Installation of a lime spray dryer (LSD) and replacement of the Lodge-Cottrell ESP with a pulse jet baghouse would remove 90% of the SO_2 from the flue gas. A baghouse is necessary to produce additional contact time that allows the SO_2 absorption reactions to be complete. CMC coal would continue to be burned, so tax exemptions would be available for this option.

(i) The current generation of spray dryer FGD processes use lime. Sodium carbonate is more reactive than lime but is more expensive and requires special disposal techniques for the by-products. Limestone, although less expensive than lime, is unsuccessful in this process due to low reactivity (Ref. 29, App. D, p. 1).

(ii) Lime spray dryer FGD uses lime slurry, or calcium hydroxide, to absorb SO_2 in well-distributed atomized slurry droplets. Much development work has achieved uniform distribution and thorough mixing of the flue gas and atomized lime slurry to ensure high SO_2 collection rates. The liquid-phase reaction forms calcium sulfite and calcium sulfate which remain as dry particulate matter in the gas stream after the heat of the flue gas evaporates the water from the droplets. Remaining particulate matter is collected in a downstream baghouse where up to 20% additional SO_2 removal occurs with the unreacted slurry droplets in the filter cake built up on the bags.

(iii) Guarantees of at least 90% removal efficiency for LSD systems followed by fabric filters are commonplace for full-scale new facilities constructed in the 1990s. From 1991 to 1996, a total of 12 units ranging in size from 65 MW to 385 MW were equipped with LSD technology and baghouses resulting in SO_2 control efficiencies of 92% up to 95% for coals containing between 1.3% and 2.1% sulfur (Ref. 29, App. D, ABB technical paper).

(iv) Sargent & Lundy report the largest commercial LSD unit is about 230 MW, requiring at least three modules per unit at Centralia Plant (Ref. 29, App. D).

(v) Lime spray dryer technology is proven on utility boilers and offers certain advantages over wet limestone systems. These advantages include lower energy and water requirements, reduced slurry pumping requirements, flue gas discharge temperature above saturation, no potential for gypsum scale, use of carbon steel instead of alloy steel construction, and continued use of existing stacks in retrofit situations.

f. <u>Partial Scrubbing - Lime Spray Dryer at 75% Reduction Each Unit.</u>

Installation of a lime spray dryer (LSD) in the ducts between the existing ESPs would remove 75% of the SO_2 from the flue gas. Equipment layout considerations will allow only the second ESP to treat LSD residual particulate matter. CMC coal would continue to be burned, however, since the CDM Target Solution is not achieved, this option would receive no tax exemptions enacted by HSB 1257.

(i) The current generation of spray dryer FGD processes use lime. Sodium carbonate is more reactive than lime but is more expensive and requires special disposal techniques for the by-products. Limestone, although less expensive than lime, is unsuccessful in this process due to low reactivity (Ref. 29, App. D, p. 1).

(ii) Lime spray dryer FGD uses lime slurry, or calcium hydroxide, to absorb SO_2 in well-distributed atomized slurry droplets. Much development work has achieved uniform distribution and thorough mixing of the flue gas and atomized lime slurry to ensure high SO_2 collection rates. The liquid-phase reaction forms calcium sulfite and calcium sulfate which remain as dry particulate matter in the gas stream after the heat of the flue gas evaporates the water from the droplets. Remaining particulate matter is collected in the downstream ESP, but no significant additional SO_2 removal occurs there.

(iii) PacifiCorp operates a dry lime spray dryer followed by an ESP at its Wyodak Plant. Experience shows SO_2 removal is limited to about 75% to 80% with the ESP following the lime spray dryer.

(iv) Sargent & Lundy report the largest commercial LSD unit is about 230 MW, requiring at least three modules per unit at Centralia Plant (Ref. 29, App. D).

(v) Lime spray dryer technology is proven on utility boilers and offers certain advantages over wet limestone systems. These advantages include lower energy and water requirements, reduced slurry pumping requirements, flue gas discharge temperature above saturation, no potential for gypsum scale, use of carbon steel instead of alloy steel construction, and continued use of existing stacks in retrofit situations.

g. <u>All External Coal.</u>

Use of all external coal would reduce SO_2 emissions by about 68%. A coal off-loading facility to process 6 million tons of coal per year would be needed along with boiler modifications and blending of external coals to optimize emissions and fuel firing characteristics in the boilers.

Since the CMC mine would not continue to be utilized and the CDM Target Solution is not achieved, this option would receive no tax exemptions enacted by HSB 1257.

(i) Centralia Plant is currently receiving up to 22% of its fuel supply as external coal (Ref. 29).

(ii) Respondent believes there is a cost and reliability risk associated with being a captive customer of the railroads which exposes the Respondent to unilateral cost escalations and potential interruptions in supply due to rail traffic approaching capacity (Ref. 29, p. 34).

(iii) Rail line capacity in the region is near maximum which would create some uncertainty in coal supply for the Plant (Ref. 29, p. 34).

(iv) The size of Centralia Plant's coal inventory is not currently limited by either state or federal regulations. The current targeted stockpile size of 800,000 tons is determined by operational and economic considerations. The stockpile has been as high as 2,629,000 tons in 1982 (Ref. 6, p-16).

None of the SO_2 reduction technologies which simultaneously remove NO_x are considered to be either commercially available for application or cost-effective (Ref. 29, p. 65-66). Very few of the combined systems have been demonstrated at a utility level greater than or equal to 100 MW. Most combined systems rely on by-product sales to off set their capital expense. The sulfur content of coal burned at Centralia Plant is relatively low which reduces the payback potential.

3.3 Emission Reduction to be Achieved by Additional SO_2 Controls

3.3.1 Effectiveness of SO_2 Control Options

The EPA benchmark for Phase II SO_2 allocations is an emission rate of 1.2 lb/MBtu. The current Centralia Plant SO_2 1-hour emission limit of 1000 ppm (dry basis @ 7% O_2) is equivalent to an annual average of 2.45 lb/MBtu (Ref. 29).

The July 1997 CMC mine plan provides coal to the Centralia Plant through the year 2027. The mine's extraction strategy will change after the year 2002 to concentrate on the most economical seams and blend coal solely for heat content rather than sulfur content. The most cost-effective way of operating the CMC mine is to allow post-combustion controls to reduce SO_2 emissions rather than blend the coal for lower sulfur content. The mine plan is a dynamic blueprint for CMC operations, changing in response to new information about the quantity, location, and properties of the active and prospective coal seams (Ref. 42).

Respondent used an uncontrolled emission rate of 2.06 lb/MBtu, or 88,680 tons/yr, as the basis for its SO_2 emission reduction projections (Ref. 29, p. 32).

In Acid Rain Program Phase I emission reductions, approximately 50% of the FGD units installed included no spare absorber capacity. Overseas markets use single absorber modules. A study by the North American Electric Reliability Council covering operations from 1986 to 1989 showed that the equivalent forced outage rate for units with no spare absorber modules was 0.68% compared to 0.26% for units with spare absorbers (Ref. 29, App. D).

Controlled emissions to be achieved by the candidate SO_2 control technologies using Respondent's basis that continued operations are represented by burning primarily CMC coal with an average emission rate of 2.06 lb/MBtu for the years 2002 through 2027 at 70% capacity factor are presented below (Ref. 29, p. 32). In addition, the annual emissions reduced compared to maximum possible allowed emissions at 70% capacity factor is shown for each technology. An emission rate of 2.45 lb/MBtu corresponding to operation that barely meets the 1-hour SO_2 emission standard is used to determine the maximum allowed emissions at 70% capacity factor. This quantity is not the same as potential to emit, which is based on continuous round-the-clock operation at 1,000 ppm stack concentration.

	SO_2 Controlled	Emissions Reduced (tons/yr)	
Control Technology	Emissions (tons/yr)	vs. Baseline	vs. Maximum
Natural Gas	344	88,336	105,044
LSFO Scrubbing	8,868	79,812	96,520
ASFO Scrubbing	8,868	79,812	96,520
LSD, All External Coal	8,868	79,812	96,520
LSD, Baghouse, CMC	8,868	79,812	96,520
LSD, partial scrub, ESP	22,170	66,510	83,218
All External Coal	26,568	62,112	78,819

3.3.2 Effect of Options on Other Air Pollutants

If wet scrubbing is selected for emissions reductions, a localized brown haze is reported to possibly appear even when NO_x emissions are low. Annual total emissions of NO_x, PM, and CO are not expected to change based on use of the evaluated SO_2 technologies.

External coal from the Powder River Basin generally will produce a fly ash with lower SO_3 due to lower sulfur in the coal, resulting in higher fly ash resistivity. This will tend to cause lower collection efficiency of particulate matter in the ESPs compared to the performance with coals having a lower resistivity ash. Fly ash resistivity is inversely proportional to the concentration of SO_3 and water in the flue gas and the sodium, potassium, and carbon content of the ash (Ref. 42). Although its fly ash resistivity is higher, Powder River Basin coal has lower ash content than typical CMC coal, so the emissions from the ESP should not change significantly.

A wet FGD system is not expected to cause carryover of calcium sulfate ($CaSO_4$) particles or other aerosols because a high efficiency mist eliminator will capture any entrained scrubber reaction products. Vendor literature indicates that collection efficiencies of entrained liquid from FGD absorber gas streams are greater than 95% for mist droplet diameters of 20 μm and larger. In tests conducted at EPRI's Environmental Control Technology Center, mist eliminators limited the carryover of scrubber slurry to 0.0005 gal/min/ft^2, half of the NSPS PM emissions limit, or lower at flue gas velocities of up to 16.5 ft/sec. The carryover rate decreased slightly as the gas velocity increased in the tests suggesting that penetration of small particles through the mist eliminators account for most of the droplet carryover.

FGD systems are capable of forming sulfuric acid mist when SO_3 contacts moisture in a wet scrubber. These systems typically remove 30% to 50% of the SO_3 entering the absorber vessel. Acid mist plumes become visible when the SO_3 or acid concentration exceeds 15 ppm; at Centralia Plant the SO_3 concentration entering the absorber vessels is expected to not exceed 10 ppm, so no acid plume is envisioned. Total PM emissions from the FGD system, including the condensible fraction, will not increase compared to the total PM which enters FGD absorbers from the ESPs.

3.3.3 Other Environmental Impacts

Control technologies which provide pollution prevention should be given preference by the Respondent when making the final control technology selection (Ref. 1, RCW 70.94.301(4)).

- PEPA and WDOE policies define pollution prevention as the reduction or elimination of pollutants at their source so that waste is not generated.
- PSection 301(4) of RCW 70.94, the Washington Clean Air Act, states "...reasonably available control technology (RACT) is required for existing sources. In establishing technical standards defined in subsection (2) of this section, the permitting authority shall consider and if found appropriate, give credit for waste reduction within the process."
- PFrom a pollution prevention point of view, the fuel management options minimize waste disposal more than the other control options. Use of lower sulfur coal and natural gas reduce SO_2 without generating more waste and should qualify for a waste reduction credit.

3.3.3.1 Water Quality

Wet scrubbing systems (LSFO & ASFO) consume water, at an estimated rate of 1,567 gallons per minute (gal/min). A dry scrubbing system (LSD) is estimated to consume about one-third less water than a wet system. Water from existing effluent ponds which collect Centralia Plant's waste water can be used for scrubber make-up water. Some of the water would be returned for recycling after de-watering of the scrubbed waste. Ammonia contact with water could change the quality of the waste water effluent requiring some additional treatment prior to discharge. The impact of the options on wastewater discharge is summarized below:

SO_2 Option	Waste Water Impacts
Natural Gas conversion	Water quality improved due to reduced runoff from coal and ash piles. NPDES discharge quantities reduced 21%.
LSFO Scrubbing	Wet scrubber consumes waste water; NPDES discharge quantity reduced by 86%. Chloride content of scrubber blowdown, about 8,000 ppm, will affect water quality.
ASFO Scrubbing	Wet scrubber consumes waste water; NPDES discharge quantity reduced by 86%. Unreacted ammonia in scrubber blowdown may affect water quality.
LSD, All External Coal	Dry scrubber consumes waste water; NPDES discharge quantity reduced by 63%.
LSD, Baghouse, CMC	Dry scrubber consumes waste water; NPDES discharge quantity reduced by 63%.
LSD, partial scrub, ESP	Dry scrubber consumes waste water; NPDES discharge quantity reduced by 63%.
All External Coal	No change from present operations.

3.3.3.2 Solid and Hazardous Waste

Each of the SO_2 control options has its own mix of wastes to be disposed and by-product with potential commercial use. For scrubbing options that produce waste that cannot be sold, the scrubber waste must be mixed with fly ash prior to disposal in the mine in a limited use unlined landfill. Between 500,000 and 800,000 tons/yr of coal ash are produced depending on the quantity of coal consumed and its ash content. About 250,000 to 300,000 tons/yr is sold as an additive to concrete, while the balance is returned to the CMC mine for backfill. Waste analyses indicate that the scrubber effluent and bottom and fly ash are not dangerous wastes under Washington's rules as determined according to WAC 173-303. Coal combustion by-products, including scrubber wastes, are exempt from hazardous waste classification under federal RCRA rules. The fuel blending options all result in reduced quantities of fly ash and bottom ash returned to the mine when compared to current operations (Ref. 29, p. 65). Each of the SO_2 control options includes waste disposal as an evaluated cost and revenue from sale of by-products as an offset to costs (Ref. 29, p. 66).

Control Technology	Solid Waste Impacts	Hazardous waste Impacts
Natural Gas	No ash generated	No change anticipated
LSFO Scrubbing	443,667 tons ash to mine 263,293 tons gypsum sold	No change anticipated
ASFO Scrubbing	443,667 tons ash to mine 173,661 tons $(NH_4)_2SO_4$ fertilizer sold	Safety & disposal issues from use of ammonia
LSD, All External Coal	148,972 tons ash/Ca product; new landfill	No change anticipated
LSD, Baghouse, CMC	614,076 tons ash/Ca product to mine	No change anticipated
LSD, partial scrub, ESP	562,732 tons ash/Ca product to mine	No change anticipated
All External Coal	110,029 tons ash; new landfill needed	No change anticipated

Any new federal landfill upgrade requirements will impact existing solid waste costs and be resolved according to solid waste rules regardless of the outcome of this RACT evaluation. This RACT evaluation does not impose any new solid waste regulations or requirements.

The newest CMC mine plan projects coal supply to the Centralia Plant through the year 2027. Mine extraction strategy will change after 2002 to concentrate on the most economical seams and blend coal solely for heat content rather than sulfur content. The most cost-effective way of operating the CMC mine is to allow post-combustion controls to reduce SO_2 emissions rather than blend the coal for lower sulfur content. The mine plan is a dynamic blueprint for CMC operations, changing in response to new information about the quantity, location, and properties of the active and prospective coal seams.

3.4 Impact of Additional SO_2 Controls on Air Quality

3.4.1 Ambient Levels of SO_2 and Sulfates

PacifiCorp indicates that the CMC mine plan has been revised from the 1996 mine plan used for emissions and economic projections for the CDM process. Current SO_2 emission projections for the years 1998 to 2002 are lower than projections presented in 1996. Interim reductions to further minimize SO_2 emissions in the period before control technology can be installed are not possible (Ref. 29, p. 20). Therefore, ambient levels of SO_2 are very likely to remain similar to the past few years until additional control technology is implemented.

Modeled increments to ambient concentrations due to Centralia Plant emissions were predicted in the 1997 study "An Assessment of the Health Risks Due to Air Emissions from the Centralia Power Plant" by Jonathan Samet et al. of the Johns Hopkins University Department of Epidemiology and Kirk Winges of McCulley Frick & Gilman. The model CALPUFF was used with wind field inputs from the model CALMET to generate estimates of hourly and annual pollutant concentrations within 150 miles of the plant in an area stretching roughly from Bellingham, Washington to Salem, Oregon (Ref. 40, p. 5-7). The results from this modeling indicate the following:

a. Peak 24-hour SO_2 concentrations of 9 to 10 $\mu g/m^3$ (0.004 ppm) are predicted southwest of the plant for forecasted emissions in the year 2000 with 90% SO_2 reduction in effect at the plant. This level represents about an 85% decrease in modeled peak concentration compared to the case with no SO_2 emission controls (Ref. 40, App. C).
b. Annual average SO_2 concentrations of 0.7 to 0.8 $\mu g/m^3$ (< 0.0003 ppm) are predicted north-northeast of the plant for the year 2000 emissions with SO_2 emission controls achieving 90% reduction from the plant. This predicted concentration contrasts with a predicted annual average of 5.5 to 6.0 $\mu g/m^3$ with no SO_2 emission controls (Ref. 40, App. C).
c. The population-weighted annual average SO_2 concentration over the entire modeling domain is predicted to be 0.091 $\mu g/m^3$ for population levels in the year 2000 and a 90% reduction in SO_2 emissions over the no control case (Ref. 40, p. 48 & Table 6).
d. The modeled SO_2 concentrations are all substantially below the applicable State and National Ambient Air Quality Standards.
e. Peak 24-hour SO_4 concentrations of 0.3 $\mu g/m^3$ south-southwest of the plant are predicted for the case of a 90% reduction applied to the SO_2 emissions projected for the year 2000. The modeled daily maximum concentration is reduced by about 85% compared with the predicted SO_4 levels without SO_2 emission controls (Ref. 40, App. C).
f. Annual average SO_4 concentrations of 0.01 to 0.02 $\mu g/m^3$ northeast and south of the plant are predicted for year 2000 with plant SO_2 emissions reduced by 90%. The modeled concentration decreases from a level ranging from 0.09 to 0.10 $\mu g/m^3$ with no SO_2 emission controls at the plant (Ref. 40, App. C).

As emissions are transported away from the Plant, atmospheric chemical and photochemical changes occur, along with physical dispersion in the air and deposition to surfaces. Over time, a portion of the emitted SO_2 will remain gaseous and a portion will be converted to sulfuric acid and sulfate aerosols, or fine particles. The conversion of SO_2 to sulfate (SO_4) aerosol, a component of $PM_{2.5}$ (particles of diameter less than 2.5 μm), is a non-linear process that depends on atmospheric conditions including relative humidity. Both gas and aerosol forms of the original SO_2 emissions are removed from the atmosphere by dry and wet deposition, the latter occurs usually by rain or snow (Ref. 29, p. 52). The fate of the Centralia Plant's SO_2 emissions a considerable distance away from its stacks will vary considerably depending on weather conditions; however, a significant decrease in SO_2 emissions will also reduce the resulting concentration of SO_4 aerosol, but the amount of this reduction cannot be easily quantified except with complex atmospheric dispersion models that take into account the formation of secondary pollutants, such as sulfate, through chemical reactions.

3.4.2 Human Health Effects

In the Samet et al. 1997 study entitled "An Assessment of the Health Risks Due to Air Emissions from the Centralia Power Plant", emissions from the Centralia Plant were modeled to generate hourly and annual pollutant concentrations for a grid of points in a region within 150 miles of the plant stretching roughly from Bellingham, Washington to Salem, Oregon. The health effects assessed in this study arise from exposures to particles, including acidic particles, and SO_2 both before and after installation of SO_2 controls. Some of the SO_2 converts to sulfate (SO_4), a fine aerosol assumed to all be less than 2.5 µm in diameter that will primarily be in the form of ammonium sulfate (Ref. 40, p. 6-7).

Modeled pollutant concentration increments were combined with population data to produce increments in exposure. The population exposure increments were combined with risk coefficients describing the mortality or morbidity associated with the pollutants to characterize the risk from plant emissions. The risk estimates for mortality and morbidity associated with the Centralia Plant should not be construed as actual mortality and morbidity, but may be used for comparing to estimated risks from other air pollution sources (Ref. 40, p. 63). Health impacts from SO_2, the resulting SO_4 aerosols, and other components of fine particulate matter were determined for a 90% reduction in SO_2 emissions, and are summarized as follows (see TSD '5.4.2 Particulate Matter, Health Effects for additional discussion of sulfate as fine particulate matter):

a. The risk of premature mortality from the plant is estimated throughout the study area to be 1.2 to 13.0 with 90% emission reduction depending on the assumptions selected for estimating risk. For King County alone, the study projected using the same methodology and 1990 data a risk of premature mortality due to all air pollution based on current ambient measurements of 2,053 (Ref. 40, pp. 7 and 64).
b. Using rates provided by the National Center for Health Statistics, the study estimated the numbers of emergency room visits and outpatient visits for asthma by county for the year 1990. Visits attributable to Plant operations represent a very small proportion of the total (Ref. 40, p. 64).
c. Emergency room and doctor office visits estimated to result from plant emissions range from 26 to 41 once SO_2 controls are installed. This compares with an estimated total of 260,000 asthma-related visits each year in the study area (Ref. 40, p. 61 and Table 18).
d. Exposures to air pollution resulting from Centralia Plant emissions for 5.5 million people residing within a 150-mile radius of the plant were estimated with a state-of-the-art pollution model. Compared to the population's total exposure to air pollution, the Centralia Plant is a minor contributor even without SO_2 controls, and its contribution is substantially reduced with the addition of pollution controls (Ref. 40, p. 65-66).

3.4.3 Visibility Improvement

The frequency of days with perceptible changes in visibility will not change proportionally with changes in Centralia Plant emissions. If a background visual range of 100 km is assumed, the impact of the installation of additional SO_2 controls would provide the following changes in the frequency of perceptible visibility degradation (i.e., a change of one or greater deciview) on Aclear@ days at any Class I area in the Pacific Northwest, based on modeling using MESOPUFF-II (Ref. 18, p. 16-17):

SO_2 Emissions (tons/yr)	Control Level (avg.)	No. of Days of Perceptible Change in Visibility	% of Clear Days Obscured
70,000	0%	36	26%
35,000	50%	13	9%
21,000	70%	4	3%
14,000	80%	2	1%
10,000	86%	2	1%
7,000	90%	0	0%

Visibility will be improved at Mount Rainier National Park and other Class I areas by the use of SO_2 controls consistent with the CDM Target Solution assuming the validity of the underlying documents is correct. These improvements may be difficult to observe because of growth in the Seattle-Tacoma urban area offsetting these gains shortly after they are achieved, but this does not mean such efforts are fruitless. To the contrary, visibility would become even worse under the "no action" scenario.

An estimate of the economic valuation that region residents in southwestern British Columbia, western Washington, and northwestern Oregon place on visibility improvement resulting from SO_2 emissions reductions at the Centralia Plant were estimated by Nothstein and Brown using willingness to pay methods and NPS modeling results. For an initial visual range of 40 miles and a visibility valuation coefficient of $175, the total valuation of benefits for visibility improvement on the part of residents only was estimated to be $8.9 million for 70% SO_2 reduction and $11.5 million for 90% SO_2 reduction. The total valuation of benefits for improvements in visibility including the effect of nonresidents and foreigners recreational values in addition to residents' values was estimated to be $10.7 million for 70% SO_2 reduction and $14.1 million for 90% SO_2 reduction (Ref. 32).

3.4.4 Odor and Other Nuisance Issues

Odor is not expected to be an issue for any of the SO_2 emission reduction technology alternatives, although a slight potential exists for ammonia slip from ASFO that may cause ammonia odor. The degree of ammonia slip is expected to be minimal, and the ASFO technology is not expected to cause odor nuisances in the ambient air. Further odor complaints are not expected due to emissions of SO_2 from the Centralia Plant.

3.4.5 Acid Deposition

The control of emissions from the Centralia Plant were estimated to produce significant reductions in deposition in the immediate vicinity of Centralia and in the Cascade and Olympic mountains. In the Cascades, the modeled wet deposition rate of sulfate was reduced about 30 percent with 90 percent control of SO_2 from the Centralia Plant (Ref. 7, Appendix C, p. vii).

The installation of SO_2 controls should reduce acidic deposition impacts in direct relation with the reductions achieved. Since modeling indicates that the Centralia Plant presently contributes about 30% of the total sulfur loading that high elevation lakes in Mount Rainier National Park can sustain, if emissions were reduced by 50% the Centralia Plant would contribute about 15% of the sustainable loading in these lakes. If emissions were reduced by 80% Centralia Plant's contribution would drop to approximately 5% of the loading these lakes can sustain (Ref. 18, p. 16).

Assuming a 90 percent reduction in sulfur dioxide emissions were to occur, the major reduction would occur close to the plant. Downwind reductions would be observed throughout the state, primarily north of the plant, reaching maximum values in the southeast Olympic National Park and in the central Cascades, in the areas of highest rainfall. In the Cascades this would represent an approximately 30 percent decrease in the annual wet deposition rate (Ref. 19, p. 58).

The total wet deposition in the vicinity of Stevens Pass is estimated to be 0.05 eq/m^2/yr now and 0.04 eq/m^2/yr in 1999. Researchers from the National Swedish Protection Board have suggested a standard of 0.03 eq/m^2/yr to maintain most surface waters in a healthy state and 0.02 eq/m^2/yr for sensitive waters (Ref. 19, p. 47).

A wet sulfate deposition rate of less than 20 kg/ha/yr has been selected as a goal in the joint U.S. - Canada Memorandum of Intent on the reduction of acid deposition in eastern North America. Some Canadian officials, researchers in both countries and environmentalists argued for a goal of between 14 and 17 kg/ha/yr. Current rates of deposition in New York and southern Quebec range from 38 to 46 kg/ha/yr (Ref. 19, p. 47).

For protection of sensitive lakes and streams in Mount Rainier National Park and North Cascades National Park, an interim nonmarine sulfur deposition guideline of 20 meq/m^2/yr (about 3 kg S/ha/yr; 9 kg SO_4/ha/yr) is recommended. This recommendation for maximum sulfur loading to these two parks is predicated on the following:

a. The recommended sulfur loading will not necessarily protect all sensitive aquatic resources at all times. This recommended loading is adequate for protecting at least 95% of the resources from chronic acidification, but it may not be adequate for long-term protection of the most sensitive resources.
b. The recommended sulfur loading may not protect aquatic resources from episodic acidification from either sulfur or nitrogen deposition. Episodic acidification will precede chronic acidification in many systems, particularly in view of the importance of snow to the hydrologic budgets of the alpine lakes.
c. The recommended sulfur loading does not address possible accumulation of nitrates in low temperature lakes that remain ice covered for most of the year (Ref. 4, p. ix).

3.5 Costs of the Additional SO_2 Controls

3.5.1 Elements of Total Capital Costs

The cost estimate developed for this analysis reflects a system design that would be capable of achieving the CDM process target emission levels in the most cost effective manner (Ref. 29, App. D p. I-1). In this regard, the cost estimates do not follow a traditional RACT approach, but instead seek to achieve the indicated outcome as efficiently as possible. Capital cost estimates are based on a study by Sargent & Lundy of limestone forced oxidation (LSFO) applied to the Centralia Plant, plus further study investigating use of lime spray dryer technology, and a Raytheon survey of ammonium sulfate forced oxidation (ASFO). Industry literature supplemented these sources and provided estimates for the option of conversion to natural gas.

Capital costs of full-scrubbing FGD at Centralia Plant are estimated to range from \$120 to \$160 per KW of electrical capacity with a best estimate of \$140 per kW. This cost is judged to have an accuracy of ∀15%. The capital costs for 13 Phase I units retrofitted with FGD by January 1, 1995 averaged about \$257 per kW when reconciling the cost bases of the reported plant costs. (Ref. 29, App. D)

3.5.2 Elements of Annual Operating Costs

The control technology with the lowest level of emissions is to be evaluated first. If the annualized cost of this additional control at the source over the life of the installation is reasonable, then the basis for setting a RACT emission limit has been established but operational considerations may need to be incorporated into the actual setting of the limit (Ref. 5).

Operating costs are estimated as incremental costs for each option relative to the status quo. The elements of operation and maintenance (O&M) costs that comprise the total annual cost figure are use of reagent and makeup water, electricity necessary to operate new fans, pumps, conveyors, and other similar equipment installed as part of the SO_2 control option, operating labor costs, maintenance expenses separate from in-house labor and materials, and waste disposal costs or by-product revenues (Ref. 29, p. 32).

O&M costs reflect a baseline capacity factor of 70%. This value was chosen because the average capacity factor for the plant over the last five years has been close to this value, and it is expected as the future level of operation. Reagent and O&M costs were derived from the Electric Power Research Institute (EPRI) model FGDCOST as well as site specific estimates. Reagent costs are also based on estimates from potential suppliers (Ref. 29, p. 46).

3.5.3 Cost Discussion

The costs reflected in the SO_2 control options are plant specific and not based on the EPA cost control manual, as is typically used for a RACT assessment and determination. Plant specific costs for only those options that achieve the CDM Target Solution of 90% reduction produce a set of options that is not comparable to usual RACT decisions.

The RACT determination for Minnesota's King Plant made the following determination with respect to benefit/cost studies:

a. Minnesota officials believed it would be good evidence of the requirements of the public convenience if quantification of the benefits resulting from a proposal is possible. However, the presentation of a quantitative benefit/cost analysis was not accepted into the record. Minnesota officials determined that some benefits are inherently unquantifiable; others can only be quantified if a myriad of assumptions are made. In either case, assigning numerical quantities to the benefits would be an academic exercise, with no assurance that the result would likely reflect reality (Ref. 7, Appendix A, p. 10).
b. Many of the benefits to be achieved by the reduction of SO_2 emissions are at this stage of scientific analysis unquantifiable. This was the position of Northern States Power Company when it urged the exclusion of benefit/cost studies from the King Plant RACT decision (Ref. 7, Appendix A, p. 11).
c. Minnesota officials concluded that a reduction in SO_2 emissions is both a benefit and a policy that the state wishes to pursue (Ref. 7, Appendix A, p. 11).

At the request of the Legislature, the Washington Department of Ecology initiated an acid deposition benefit/cost study which was performed by Envirometrics in 1986, 7 years earlier than the Minnesota King Plant RACT decision. This study quantified the benefit/cost of acid deposition as follows:
a. The net societal cost of a scrubber installation was $823.4 million over a 30 year period.
b. The benefits from reducing SO_2 emissions by 90 percent provided a reduction in environmental damages of $21.8 million (Ref. 7, Appendix C, p. ix).
c. The least social cost option from the Washington Department of Ecology study was concluded to be no requirement for further controls at Centralia Plant at that time (Ref. 7, Appendix C, p. ix).
d. The study also concluded that any control of SO_2 emissions from substantial point sources, such as the Centralia Plant was generally going to be more cost effective than further controls on motor vehicles in reducing environmental damage (Ref. 19, p. 153).

A 1992 Report to Congress from the National Acid Precipitation Assessment Program concluded that it is not yet possible to express benefits of SO_2 reductions in dollar terms, although, when feasible, it is planned to do so in the future as part of the analysis of costs and benefits (Ref. 15, p. 2).

The US Forest Service in collaboration with Economics Professor Dan Hagan of Western Washington University estimated in 1995 the discounted present value of benefits for Goat Rocks Wilderness Area and Alpine Lakes Wilderness Area at over $3 billion each. The methods utilized to estimate economic existence values for wilderness areas were based on an assumed value of $1 per household, a 40 year life for the power plant and a growth rate of 3%. Similar valuation techniques using an estimated value of $20 per household were applied to the Grand Canyon National Park in effort to quantify the value of good visibility (Ref. 17).

Capital costs are converted to an effective annual amount based on the 30-year project life and 9.13% discount rate. Incremental O&M costs, the additional costs or credits compared to 1997 operations, are combined with incremental property taxes, where applicable, and the sum multiplied by the levelizing factor of 1.32, which is based on a 30 year project lifetime, an owner-weighted discount rate of 9.13%, and an annual escalation rate of 3.0%. The levelized O&M cost is then combined with the annual incremental fuel cost, SO_2 Acid Rain Program allowance benefit, and the annualized capital recovery to obtain the total annualized cost for the option. The incremental fuel cost of external coal, which is subject to sales tax, is considered to be zero, i.e. no price difference exists between CMC and external coal (Ref 29, p. 43-45). The capital and total annualized costs of the SO_2 control options evaluated for this RACT analysis to meet the CDM Target Solution are summarized below for each option.

The SO_2 control technologies presented in the RACT submittal were compared based on cost effectiveness, or cost per ton of emissions reduced. The Centralia Plant's cost effectiveness numbers are based on emission reductions from the projected average level of uncontrolled emissions from 2002 through 2027. A more appropriate expression of cost effectiveness is a range of dollars per ton reduced based on the SO_2 emission reduction compared to both baseline emissions and the maximum allowed emissions, which were presented in '3.3.1 above. Potential emissions when the Plant operates at 70% capacity factor would be 105,388 tons/yr if the emission concentration was at the 1000 ppm SO_2 limit. A range of cost effectiveness values is presented for each option.

1. Natural Gas Conversion - Both Units. The high fuel cost for natural gas demonstrates that this option is not economically feasible compared to other available methods for reducing SO_2 emissions (Ref. 29, p. 46). The annual O&M cost plus incremental fuel cost relative to burning coal is over 6 times larger for natural gas conversion than for the next most expensive O&M option. The cost of natural gas conversion to achieve an annual SO_2 emission level of 344 tons/yr at 70% capacity factor is the following:

	Capital Cost (1,000$)	Total Annualized Cost (1,000$)	SO_2 Emissions Removed (tons/yr)	Cost Effectiveness ($/ Ton Removed)
1997$	$24,559	$100,212	88,336 to 105,044	$954 to $1,134

2. Full Scrubbing - Limestone Forced Oxidation (LSFO). Savings have been realized from the 1994-95 RACT submittal and analysis because this option utilizes a single absorber per unit in lieu of two absorbers per unit. Reduced redundancy is consistent with the CDM Target Solution which seeks greater average reductions at lower cost than a typical RACT or NSPS-driven outcome. Studies in the National Acid Precipitation Assessment Program report indicated that costs of wet lime/limestone scrubbers would be in the range of $400 to $1000/ton of SO_2 removed and the median cost was about $700/ton removed. Reported costs of actual Phase I units are at the lower end of this range because utilities are installing scrubbers on the highest SO_2 emitting units.

All or part of the gypsum produced by a LSFO system could be sold in the area of the Centralia Plant to wallboard plants which currently pay a considerable cost to transport gypsum to their plants. Some cement plants have also shown interest in buying gypsum from nearby sources in the area (Ref. 29, App. D). The cost of installing and operating LSFO to achieve an annual SO_2 emission level of 8,868 tons/yr at 70% capacity factor is the following:

	Capital Cost (1,000$)	Total Annual Cost (1,000$)	SO_2 Emissions Removed (tons/yr)	Cost Effectiveness ($/ Ton Removed)
1997$	$212,419	$24,727	79,812 to 96,520	$256 to $310

3. Full Scrubbing - Ammonium Sulfate Forced Oxidation (ASFO). For those options that achieve the CDM Target Solution level of emissions, ASFO is the most cost effective at $194 to $234 per ton of SO_2 reduced.

A large market for ammonium sulfate exists in the fertilizer industry. The cost of producing ammonium sulfate from an ASFO system should be very cost competitive because the sulfur is present in the stack gases at no additional cost. The economic advantage of producing ammonium sulfate increases as SO_2 removal efficiencies rise above 90%. In 1993, the U.S. wholesale price of granular ammonium sulfate ranged from $75 to $130 per ton. The ASFO capital cost is higher than that of LSFO due to the use of a prescrubber, compactors and dryers to produce a granular product, and higher process contingency. This higher capital cost is offset by the lower variable operating cost resulting in the total annual levelized cost for ASFO to be 24% lower than for LSFO, based on a byproduct credit of $90/ton for ammonium sulfate compared with $5/ton for wall-board quality gypsum (Ref. 29, Appendix D).

The economic advantage of the ASFO process becomes more pronounced when a plant burns higher sulfur coal. The cost of ASFO to achieve an annual SO_2 emission level of 8,868 tons/yr at 70% capacity factor is the following:

	Capital Cost (1,000$)	Total Annual Cost (1,000$)	SO_2 Emissions Removed (tons/yr)	Cost Effectiveness ($/ Ton Removed)
1997$	$225,928	$18,983	79,812 to 96,520	$194 to $234

4. Full Scrubbing - Lime Spray Dryer and All External Coal. Conversion of the Centralia Plant boilers to burn all external coal would also require a coal off-loading facility to process 6 million tons of coal per year along with blending facilities. A lime spray dryer (LSD) would use multiple vessels, but the capital cost is expected to be substantially less than for a wet LSFO scrubber system. A new stack is not needed and carbon steel construction can be used instead of alloy steels as in a wet scrubber (Ref. 29, p. 37).

A new landfill for ash disposal would be required since the CMC mine would close within five years. However, by burning lower sulfur coal, less reagent is needed and less waste is generated compared to CMC coal. Transportation costs for coal deliveries to Centralia Plant would be more uncertain, and likely to rise, if plant operation is totally dependent on external coal. Rail cost expectations without any contingency component have been included in the assumed cost of coal (Ref. 29, pp. 34-37).

The cost of LSD with all external coal to achieve an annual SO_2 emission level of 8,868 tons/yr at 70% capacity factor is the following:

	Capital Cost (1,000$)	Total Annual Cost (1,000$)	SO_2 Emissions Removed (tons/yr)	Cost Effectiveness ($/ Ton Removed)
1997$	$180,348	$21,699	79,812 to 96,520	$225 to $272

5. Full Scrubbing - Lime Spray Dryer with New Baghouse. The new baghouse needed to increase sorption time and achieve 90% removal of SO_2 in conjunction with a lime spray dryer (LSD) would cost approximately $30 million. A pulse jet baghouse retrofit into the Lodge-

Cottrell box is estimated to be the most economical type of baghouse. Capital costs approach the costs of the LSFO option even though the existing stacks and carbon steel vessels could be used (Ref. 29, p. 36).

Waste product from the LSD could be disposed of in the CMC mine, but the baghouse catch would have to be disposed in a special landfill in the mine at an increase in cost of 50% over current ash disposal costs (Ref. 29, p. 36).

The cost of LSD with a new baghouse and continued use of CMC coal to achieve an annual SO_2 emission level of 8,868 tons/yr at 70% capacity factor is the following:

	Capital Cost (1,000$)	Total Annual Cost (1,000$)	SO_2 Emissions Removed (tons/yr)	Cost Effectiveness ($/ Ton Removed)
1997$	$189,812	$31,554	79,812 to 96,520	$327 to $395

6. Partial Scrubbing - Lime Spray Dryer at 75% Reduction Each Unit. Although a likely design for a lime spray dryer (LSD) with CMC coal and ESPs would use multiple vessels, the capital cost is expected to be substantially less than for a wet LSFO scrubber system. A new stack is not needed and carbon steel construction can be used instead of alloy steels as in a wet scrubber. However, the incremental O&M cost would be higher than with a wet system because the LSD waste cannot be sold and must be disposed in a landfill (Ref. 29, p. 36).

Installation of LSD with continued use of the ESPs and CMC coal does not achieve the CDM Target Solution. It results in annual SO_2 emissions of 22,170 tons/yr at 70% capacity factor, and has the following costs:

	Capital Cost (1,000$)	Total Annual Cost (1,000$)	SO_2 Emissions Removed (tons/yr)	Cost Effectiveness ($/ Ton Removed)
1997$	$155,142	$29,643	66,510 to 83,218	$356 to $446

7. All External Coal. Conversion of the Centralia Plant boilers to burn all external coal would also require a coal off-loading facility to process 6 million tons of coal per year along with blending facilities. Fuel blending to reduce SO_2 can be implemented sooner than Full Scrubbing because of the long lead times needed for the installation of the scrubbers.

A new landfill for ash disposal would be required since the CMC mine would close within five years. It has been assumed that coal disposal costs will increase to $10/ton in the All External Coal option because of the closing of the CMC mine and the need for a new landfill. Transportation costs for deliveries to Centralia Plant would be more uncertain, and likely to rise, if plant operation is totally dependent on external coal. Rail cost expectations without any contingency component have been included in the assumed cost of coal (Ref. 29, pp. 34-35).

Use of all external coal does not achieve the CDM Target Solution. It results in annual SO_2 emissions of 26,568 tons/yr at 70% capacity factor, and has the following costs:

	Capital Cost (1,000$)	Total Annual Cost (1,000$)	SO_2 Emissions Removed (tons/yr)	Cost Effectiveness ($/ Ton Removed)
1997$	$52,363	$5,333	62,112 to 78,819	$68 to $86

New sources of power generation which may compete with the Centralia Plant in the future will be required to meet either Best Available Control Technology requirements (BACT) or Lowest Achievable Emission Rate (LAER) both of which are more expensive than RACT. BACT and LAER involve a higher level of control requirement and less consideration of cost than utilized in RACT determinations. Therefore, implementation of this RACT determination will not cause a competitive disadvantage that did not already exist with these other resource alternatives.

The cost of generating and delivering hydroelectric energy to utilities in the northwest is anticipated to increase in the new few decades. Clark Public Utilities forecast that its projected cost of power from the Bonneville Power Administration would increase from 3.5 cents per kilowatt hour in 1997 to a range from 7 cents per kilowatt hour to 10 cents per kilowatt hour in 2017. This is greater than a 100% increase.

Tacoma Public Utilities' Rate Forecast report concludes that in the near term there will be increased concern among Northwest Utilities, their customers and the general public about the competitiveness of Bonneville Power Administration power. Further, the power rate for public utilities may lose part or all the price advantage that it has recently had over other resource alternatives.

Socio-Economic Impacts:

a. The Centralia Plant currently employs 160 people and Centralia Mining Company (CMC) employs 510 people. Four of the seven alternatives studied are expected to have a positive impact on the local economy due to jobs, materials, and services necessary during installation of emission control equipment, and to maintain employment near current levels for the life of the power plant (Ref. 29, pp. 48-49).

b. The All External Coal, Partial Scrubbing (75%) - Lime Spray Dryer, and Natural Gas Conversion options involve closing the CMC coal mine in the year 2001 and the resulting loss of about 450 jobs. Five years later another reduction of 50 to 100 employees would occur depending on the schedule for mine reclamation (Ref. 29, pp. 49).

c. PacifiCorp employees at the plant and CMC mine were projected to earn $36.5 million in wages and salaries in 1996, representing 5.8% of the total wages and salaries in Lewis County. Including indirect effects through the economic multiplier effect, the coal mine and power plant will account for 1,830 jobs, roughly one out of every 19 jobs in Lewis County. The impact would be higher if it were not for the fact that one-third of the company's work force lives and spends most of its income in Thurston County. The facilities were expected to be responsible for $61.0 million in personal income in 1996 (Ref. 29, App. I, pp. v-vi).

d. According to PacifiCorp, the coal mine and plant were to pay a total of $37.4 million in federal, state, and local taxes in 1996. The company's direct tax payments to local jurisdictions in Lewis County amounts to $4.7 million, $2.2 million in sales and use taxes and $2.5 million in property taxes. These direct tax payments constitute 10.5% of the Lewis County total tax base. Directly and indirectly, the coal mine and plant will generate $42.4 million in Washington state and local taxes, more than half of which will come from sales and use taxes (Ref. 29, App. I, pp. v and 5).

The tax relief measure passed by the Washington Legislature in April 1997 and signed into law in May 1997 will provide exemptions worth about $17 million towards the installation of pollution control equipment, and additional exemptions from property tax on the new pollution control equipment and sales tax on coal throughout the remaining project life of the plant. These exemptions will be provided only if SO_2 emissions are reduced to no more than 10,000 tons/yr and at least 70% of the coal supply is obtained from the local mine.

The value of electrical power generated in the future is the most important variable in an economic assessment of the Centralia Plant and CDM Target Solution. Economist Jim Lazar, working under contract to EPA Region X, found that the assumed avoided cost scenario, which depends on the future value of power, greatly affects the economics of the Centralia Plant Target Solution. At the avoided costs used in the PacifiCorp analysis, even with the tax package, the costs and financial risks associated with plant retrofit are challenging. Using the avoided costs PacifiCorp filed with the Washington Utilities and Transportation Commission (WUTC) in 1996, the plant retrofit is cost-effective even without the tax package. If the higher avoided costs as filed with the WUTC accurately measure the value of power from the Centralia Plant, the tax package may be viewed as offsetting the risks other than the uncertainty in avoided cost associated with control technology investment (Ref. 35).

3.6 SO_2 RACT/CDM Outcome Conclusions

In conclusion, the limits identified below meet and exceed RACT emission limits and are primarily those limits of the CDM Target Solution. The summarized limits are as follows:

a. A 12-month rolling average SO_2 limitation expressed in tons/yr and an hourly SO_2 limitation expressed in ppm dry at 7% O_2 shall be used for Centralia Plant's RACT determination.

b. Sulfur dioxide emissions shall not exceed 10,000 tons/year after the installation of the selected emission control technology.

c. The selected emission control technology shall be fully operational for the entire Plant by no later than December 31, 2002. The selected control technology for one of the two Centralia Plant units shall be fully operational by no later than December 31, 2001. If the selected control technology includes fuel supply modification resulting in less than 70% use of local coal, full compliance shall be achieved no later than December 31, 2001. A compliance strategy using fuel modification, contrary to the target solution, requires less time to implement than a post-combustion emission control system and shall be operational one year earlier to provide additional environmental benefits to offset not achieving the target solution.

d. Centralia Plant shall comply with a 1-hour emission limit of 250 $ppm_{v/v}$ dry basis corrected to 7% O_2 by no later than December 31, 2002.

The Plant owners will select the particular control technology which best fits its future needs to meet the established SO_2 emission limitation.

The RACT submittal for SO_2 by the Centralia Plant in 1997 included detailed information relevant to control strategies for SO_2 based on the CDM Target Solution. This submittal focused on control strategies that would meet the CDM Target Solution and therefore offered a smaller universe of control strategies for detailed analysis than were identified in the 1994/95 RACT review of the Centralia Plant. The control strategies evaluated in this section are those strategies that are expected to meet the CDM Target Solution, i.e., 10,000 tons per year and 250 ppm one hour average, plus two other strategies for reference and comparison. Therefore, the starting point for this SO_2 evaluation was the 90% reduction solutions and not the universe of control strategies including lesser control efficiencies as identified in the earlier RACT review. Because the basis for the evaluation in this SO_2 section had a criteria of needing to meet the CDM Target Solution, the outcome of this review was destined at the outset to exceed an evaluation based purely on RACT considerations. Therefore, the RACT emission limit established in 1995, and later withdrawn to ensure implementation of a lower SO_2 emission limit, has clearly been improved upon by a wide margin.

This approach to establishing an SO_2 emission limit is a decision made by SWAPCA because of the agreement within the CDM group (Federal Land Managers, EPA, Plant Owners, WDOE, PSAPCA) that as a minimum the CDM solution would be implemented. Upon review of the technologies and conclusions reached in the 1995 RACT Order, SWAPCA determined that a RACT emission limit similar to the previous determination (1.1 lb/MBtu), or probably a little less, is likely as an isolated RACT outcome. Therefore, nothing would be gained for the environment or the source by establishing a RACT emission limit that would not be more stringent than the limit established in the CDM process. Instead, the focus of the 1997 RACT effort has been to ensure inclusion of RACT for all pollutants of concern from the Centralia Plant and address concerns that were voiced during the process of finalizing the 1995 RACT determination. Therefore, the conclusions presented for SO_2 represent a CDM outcome that clearly exceeds the SO_2 limits established in the previous RACT Order SWAPCA 95-1787.

The limits proposed in the CDM Target Solution were achieved by considering and developing control technology strategies that are outside of the normal implementation of technologies for meeting the NSPS limits. Based on information contained in Sections 7.0 and 8.0, SWAPCA concludes that the control strategies and limitations of the CDM Target Solution represent Best Available Retrofit Technology (BART) because NSPS limits have been achieved by the CDM Target Solution. In the case of the Centralia Plant, only one scrubber vessel per unit was factored into the cost of full scrubbing. Compared to demonstrating compliance with NSPS provisions, but with the ability to operate for short periods of time without controls, this is an unconventional application of emission control technology due to the lack of redundancy. However, in providing some limited regulatory flexibility to allow the Plant to operate for short periods of time with a unit's scrubber vessel out of service for maintenance, the emission limit allows the plant to continue operating while limiting total plant-wide SO_2 emissions to less than 10,000 tons per year. While in this mode of operation, the NSPS requirement of 70% scrubbing will not be met for a unit that is undergoing maintenance. Without this flexibility, the cost for providing full scrubber vessel redundancy would have greatly exceeded typical levels of cost effectiveness under RACT and prevented the realization of substantial emission reductions as provided in the CDM Target Solution. This cost data is documented in the 1994-95 RACT evaluation and Regulatory Order. The target solution proposed by the CDM group provides for extremely high removal efficiencies and a low annual tonnage threshold that provides for maximum flexibility of plant operations and maximum reduction of SO_2 emissions.

In addition, both the House and Senate of the Washington State Legislature spent considerable time on the tax relief bill, which was unanimously supported by both chambers and ultimately signed by the Governor. This is yet another indication that the CDM Target Solution and corresponding limits were viewed by the legislative bodies as a win-win solution for both the owners of the Plant and the environment. Again, without the tax relief package provided by the Legislature, this unique control strategy likely would not have been a realizable option. The tax relief measure will provide exemptions worth about $17 million towards the installation of pollution control equipment, and additional exemptions from property tax on the new pollution control equipment and sales tax on coal throughout the remaining project life of the plant. These exemptions will be provided only if SO_2 emissions are reduced to no more than 10,000 tons/yr and at least 70% of the coal supply is obtained from the local mine.

Section 4.0

NO_x RACT EVALUATION

4.1 Impact of NO_x Emissions on Air Quality

4.1.1 Facility Emissions

Emissions of nitrogen oxides (NO_x) have been reported to SWAPCA as part of the annual emission inventory prepared by the Centralia Plant. These data are more accurate since new continuous emission monitors (CEMS) were installed at the end of 1994 (see '1.1 Plant History). Prior to operation of the Acid Rain Program CEMS, emissions were based on results of annual stack tests and total fuel combusted (Ref. 29, p. 75). Recent NO_x emissions from the emission inventories and Asnapshot@ emission rates measured during source tests in pounds relative to heat input in million Btu (MBtu) for each unit are presented below.

Year	NO_x Emissions (ton/yr)	Unit #1 (lb/MBtu)	Unit #2 (lb/MBtu)
1991	23,701	0.45	0.61
1992	20,198	0.35	0.47
1993	25,166	0.47	0.37
1994	22,268	0.34	0.46
1995	13,395	0.37	0.44
1996	18,565	0.42	0.43

The CEMS hourly data collected for the Acid Rain Program (40 CFR Part 75) are summarized in quarterly reports as quarterly, cumulative, and annual NO_x emission rates. From the complete record of hourly data, monthly average NO_x rates have been calculated and are presented below for each unit over the 12-month period of July 1996 to June 1997, the most recent annual period for which data are presently available. The source test results presented above are not necessarily representative of long-term operation since the values were obtained during stack tests which consist of three 1-hour test runs. In contrast, the CEMS data can be averaged over all hours of operation for any given time period. The data below cover a period of operation with varied electrical output in which Plant operators have been optimizing boiler performance to ensure compliance with the early election option Phase I limit of the Acid Rain Program.

Monthly Average NO_x Rate (lb/MBtu)

Month	Unit #1	Unit #2
July 1996	0.409	0.406
August 1996	0.416	0.432
September 1996	0.429	0.450
October 1996	0.404	0.462
November 1996	0.370	0.432
December 1996	0.366	0.409
January 1997	0.429	0.410
February 1997	0.356	0.343
March 1997	0.341	0.360
April 1997	0.312	0.333
May 1997	0.293	0.337
June 1997	0.339	0.331

From July of 1996 through June 1997, the average NO_x emission rate for Centralia Plant Unit #1 was 0.37 lb/MBtu. During this same period, the NO_x emission rate of Unit #2 was 0.39 lb/MBtu, annual average. The plant-wide average emission rate with the present boiler configuration was 0.38 lb/MBtu, annual average from July 1996 through June 1997.

4.1.2 Ambient Levels of NO_x and Nitrates

Nitrogen oxides (NO_x) consist of nitrogen dioxide (NO_2) and nitric oxide (NO). Although both are emitted from combustion processes, NO converts to NO_2 so total NO_x is often expressed as effective NO_2 in the atmosphere. The National Ambient Air Quality Standard (NAAQS) for nitrogen dioxide is 0.053 ppm (100 $\mu g/m^3$) annual average. Washington has established a state standard with only two decimal places of 0.05 ppm (also 100 $\mu g/m^3$) annual average.

Nitrogen oxides (NO_x) have only been monitored in SWAPCA's jurisdiction (i.e., Clark and Cowlitz Counties) since early in 1997. The average concentration of NO_2 for an eight-month period through August, 1997 is 0.013 ppm at the Mountain View High School site in east Vancouver, WA and the average concentration for a four-month period through August, 1997 is 0.004 ppm at the Castle Rock site. Ambient air monitors for nitrogen dioxide (NO_2) were located in Seattle from 1980 to 1986, and NO_2 and NO monitors were reestablished in Seattle and southeast King County in 1995. No exceedences of the 0.053 ppm, annual average, NO_2 ambient air quality standard have been recorded at any of these sites. The highest annual averages were 0.04 ppm in 1981 and 1982 at the Union Station site in Seattle (Ref. 38). The quality of data from these monitors in the 1980s was marginal. Monitor precision of ∀20% was common for this period of data collection. Data sets were often not complete; for example, the rate of valid data in 1982, from which an average for the data set was calculated, was only 50%.

Washington State University conducted an air monitoring study before and after the startup of the Centralia Plant in 1971. Continuous NO_x measurements were made at four sites near the Centralia Plant from 1972 to 1974. Annual average NO_x levels were below the NO_2 standard as shown in Table 4.1-1 (Ref. 29, p. 101).

Table 4.1-1. Ambient NO_x Annual Average Concentrations in PPM Near Centralia Plant.

Year	Bucoda site NO_x (ppm)	Rainier site NO_x (ppm)	Downtown Chehalis site NO_x (ppm)	Chehalis State Hwy. site NO_x (ppm)
1972	0.013	0.031	0.013	---
1973	0.015	0.003[a]	0.013	0.002
1974	0.011	0.002	0.007	0.001

[a] monitor replaced

The NO_x formed during combustion in the Centralia Plant boilers is mostly NO but is quickly converted to NO_2. As the NO_2 emissions are transported away from the stack a portion undergoes chemical reaction with hydroxyl radicals (OH^-) to form nitric acid which dissociates in the presence of water vapor resulting in nitrate (NO_3^-) aerosol formation. Nitric acid can also react in the atmosphere with ammonia to form ammonium nitrate particles. Formation of nitrate aerosols, considered to be $PM_{2.5}$ (particles with diameter less than 2.5 μm), depends on humidity, wind speed, temperature, and other weather conditions (Ref. 29, p. 101). Both gaseous and particle forms of NO_x and nitrates are removed from the atmosphere by wet and dry deposition, the process of pollutants returning to the ground which is enhanced by rain or snow. The effect of nitrate aerosols on ambient air quality is discussed in '5.1.2 PM Ambient Air Quality.

Review of emissions data from 1985 to 1994 and projections to 2006 indicates the NO_x emission inventory for western Washington during the summer season is dominated by on-road mobile sources which comprise 65 percent of the inventory (Ref. 30, p. 14).

Although the modeled or measured impact of NO_x emissions from the Plant is reason for analyzing NO_x as a pollutant of concern and conducting a RACT review, the current measured ambient impact of NO_x emissions should not be the only factor in making a RACT determination and establishing an appropriate RACT emission limit. Not giving sole weight to ambient impacts is supported by EPA decisions (1989 WL 266361 (EPA)) (Ref. 31) in PSD BACT cases. The same consideration applies to RACT determinations; however, the RACT emission standard is tempered more by the effect of energy, environmental, and economic collateral impacts, resulting in a less stringent standard than is obtained from BACT or PSD.

Modeled increments in ambient concentrations due to the Centralia Plant were predicted in the 1997 study "An Assessment of the Health Risks Due to Air Emissions from the Centralia Power Plant" (Ref. 40). In this work, the Centralia Plant was the only source from which emissions were modeled. The model CALPUFF was used with wind field inputs from the model CALMET to generate estimates of increments to pollutant concentrations for a systematic grid of points across the region of concern. Hourly pollutant concentrations were determined for an area within 150 miles of the plant stretching roughly from Bellingham, Washington to Salem, Oregon. The results from this modeling indicate the following (Ref. 40, App. C):

a. Peak 24-hour NO_x concentrations of 16 $\mu g/m^3$ (0.009 ppm) east-southeast of the plant are predicted to have occurred based on 1990 data. Peak concentrations of 14 to 16 $\mu g/m^3$ are also predicted for the year 2000 with no NO_x emission controls on the plant. The modeled result also assumes an increase in emissions due to increased plant utilization compared to 1990 (Ref. 29, p. 102 and Appendix L, p. 45-46).
b. Maximum annual average NO_x concentrations of 1.0 to 1.2 $\mu g/m^3$ (< 0.0006 ppm) north-northeast of the plant are predicted to have occurred based on 1990 data. The same levels are predicted in similar locations for the year 2000 with no NO_x emission controls on the plant. The modeled result also assumes an increase in emissions due to increased plant utilization compared to 1990 (Ref. 29, p. 102 and Appendix L, p. 45-46).
c. The modeled NO_x concentrations are all well below the applicable State and National Ambient Air Quality Standards of 100 $\mu g/m^3$.

4.1.3 Human Health Effects of NO_x and Nitrates

Nitrogen dioxide is an oxidant gas of low solubility, which penetrates to the small airways and alveoli of the lung. It produces a wide range of health effects including increased risk for respiratory infections, respiratory symptoms, reduced lung function, and exacerbation of chronic respiratory diseases. There are only limited epidemiologic data which remain inconclusive, largely because of problems arising in attempts to separate the effects of NO_2 from those of other pollutants (Ref. 40, p. 17).

Samet et al. of the Johns Hopkins University Department of Epidemiology produced in 1997 a study entitled "An Assessment of the Health Risks Due to Air Emissions from the Centralia Power Plant". (Ref. 40) The Centralia Plant was the only source from which emissions were modeled to generate hourly and annual pollutant concentrations for a grid of points in a region within 150 miles of the plant stretching roughly from Bellingham, Washington to Salem, Oregon. The health effects assessed in this study arise from exposures to particles, including acidic particles, and NO_x. Some of the NO_x converts to nitrate (NO_3), a fine aerosol assumed to all be less than 2.5 μm in diameter that will primarily be in the form of ammonium nitrate (Ref. 40, p. 6-7).

Modeled pollutant concentration increments were combined with population data to produce increments in exposure. The population exposure increments were combined with risk coefficients describing the mortality or morbidity associated with the pollutants to characterize the risk from plant emissions. The risk estimates for mortality and morbidity associated with the Centralia Plant should not be construed as actual mortality and morbidity, but may be used for comparing to estimated risks from other air pollution sources (Ref. 40, p. 63). Health impacts were summarized as follows (see TSD '5.1.2 Particulate Matter, Health Effects for additional findings of study):

a. The risk of premature mortality from all plant aerosol pollutants is estimated throughout the study area to be 3.3 to 34.6 with no scrubbers depending on the assumptions selected for estimating risk. The impacts are more likely to result from nitrate aerosol than from NO_x emissions. For King County alone, the study projected using the same methodology and 1990 data a risk of premature mortality due to all air pollution of 2,053 annually (Ref. 40, pp. 7 and 64).

b. Using rates provided by the National Center for Health Statistics, the study estimated the numbers of emergency room visits and outpatient visits for asthma by county for the year 1990. Visits attributable to Plant operations represent a very small proportion of the total (Ref. 40, p. 64).

In their 1992 report "Air Quality Analysis and Related Risk Assessment for the Bonneville Power Administration's Resource Program Environmental Impact Statement", Glantz et al. estimated annual cumulative exposures within an 80 km radius based on 1991 emissions data for the Centralia Plant. For population levels projected for the year 2000, the total cumulative exposure to NO_x was estimated to be 492,568 person-μg/m^3. The dispersion model used in this study did not account for chemical conversion of NO_x to nitrate (Refs. 40 and 41).

4.1.4 Visibility Impairment

The Federal Clean Air Act established a national visibility protection goal of preventing any future and remedying of any existing impairment of visibility in mandatory Class I federal areas in which impairment results from anthropogenic pollution. Class I areas are defined to be areas of special national or regional value from a natural, scenic, recreational, or historic perspective, and include Mount Rainier National Park, Alpine Lakes Wilderness, Goat Rocks Wilderness, and Mount Adams Wilderness in the vicinity of the Centralia Plant. The Centralia Plant is not causing impairment of visibility due to plume blight, or direct transport of a discernible plume from a stationary source, in any of these Class I areas. Visibility improvement strategies consist of both prevention of plume blight and also assessment of the effects from regional haze and, if possible, identification of the sources contributing to such haze. A source to which significant visibility impairment in a mandatory Class I area can be reasonably attributed is required to reduce its emissions by following the guidelines established by Best Available Retrofit Technology (BART). The contribution of Centralia Plant to regional haze at Mount Rainier National Park has been assessed in scientific studies by the National Park Service, which is mandated by the Clean Air Act to protect air quality related values in its Class I parks and monuments (Ref. 30, p. 3).

The Pacific Northwest Regional Visibility Experiment Using Natural Tracers (PREVENT) study conducted in 1990 estimated that nitrates contribute 9% to the non-Rayleigh light extinction measured at Mount Rainier National Park. The nitrate contribution was estimated to originate from several source categories including a 10-20% share from transportation and coal-fired power plants, combined. Centralia Plant NO_x is roughly the same as NO_x from the transportation sector close to Mount Rainier based on the Plant's share of 10-20% relative to all western Washington motor vehicles. The contribution of Centralia Plant NO_x to visibility impairment at Mount Rainier is, therefore, about 1% (9% x 20% x ~50%). Visibility impairment from NO_x is thought to be over an order of magnitude less than impairment resulting from SO_2 emitted from the Centralia Plant (Ref. 29, p. 32).

Four counties adjacent to Mount Rainier National Park emit 21% of the state's NO_x emissions (Ref. 4, p. 96).

Acid deposition control will improve average visibility and allow for increased enjoyment of scenic vistas across the nation. Nitrogen compounds, along with sulfur compounds, contribute to regional haze, visibility degradation and disturbance of the biochemical cycling of other nutrients and metals in ecosystems (Ref. 15, p. 2-3).

In a review of visibility data obtained from the Ashford site west of Mount Rainier, Halstead Harrison of the University of Washington Department of Atmospheric Sciences determined the contribution of nitrate to visibility impairment was about 8% of the total extinction, including Rayleigh scattering. The portion of non-Rayleigh scattering is 9% due to nitrates, in agreement with the PREVENT study (Ref. 30, App. B, p. 16).

4.1.5 Emission Limit Violations

Historically, no emission limits have been in place for NO_x emitted by the Centralia Plant. This situation changed effective January 1, 1997 when the Centralia Plant selected the early election option to comply with the Title IV Acid Rain Program NO_x emission limits for coal-fired utility boilers. Under the early election option, each unit is required to meet a NO_x limit of 0.45 lb/MBtu of heat input, averaged over a calendar year for the years 1997 through 2007. This limit then drops to 0.40 lb/MBtu, annual average beginning in 2008. Although a compliance determination cannot be made until the conclusion of 1997, boiler operation early in the year is at 0.44 lb/MBtu or less.

The ambient standard for NO_2, one component of NO_x, is 0.053 ppm, annual average. As indicated above in '4.1.2 Ambient Levels of NO_x and Nitrates, the measured levels of NO_2 near the plant have been below the ambient air standard. Therefore, no violations of either emission limits or ambient air standards for NO_x have occurred at or as a result of the Centralia Plant.

4.1.6 Odor and Other Nuisance Issues

No off site odors attributable to NO_x have ever been observed or reported or reported to SWAPCA.

4.1.7 Contribution of NO_x to Ozone in Urban Areas

Nitrogen oxides and volatile organic compounds (VOC) are precursors of tropospheric (ground level) ozone, a criteria pollutant that reduces lung function, damages the respiratory system, and sensitizes the lungs to other irritants at high enough concentrations. The NAAQS for ozone (O_3) is presently 0.120 ppm, 1-hour average, not to be exceeded more than three times in a 3-year period. The EPA adopted on July 18, 1997 a new ozone NAAQS of 0.080 ppm, 8-hour average based on the average fourth highest concentration over a 3-year period. A transition period to implement the new standard goes into effect beginning September 16, 1997. Ozone formation is a high-temperature summer phenomenon that especially afflicts urban areas and those locations immediately downwind of urban areas where motor vehicle and industrial emissions can mix and the ozone reaction can proceed to completion.

The entire state of Washington presently complies with the ozone NAAQS. Past exceedences of this standard have occurred in both the Puget Sound area 60 miles north of the Centralia Plant and in the Portland-Vancouver area 70 miles south of the Plant. However, the EPA redesignated the Seattle-Tacoma-Everett urban area as in attainment for ozone in November 1996, and the Portland, OR-Vancouver, WA interstate airshed as attainment in April 1997. The NAAQS attainment and maintenance plans for both the Puget Sound area and Portland-Vancouver airshed do not identify the Centralia Plant as a contributor to ozone formation in those urban areas. Industrial and transportation sector emissions in those respective areas have been identified as the source of ozone precursor emissions (Ref. 29, p. 105).

As part of the Samet et al. health effects study, the NO_x concentrations due to emissions from the Centralia Plant were predicted using the three-dimensional complex dispersion model CALMET. Hourly and annual average NO_x concentrations were determined for an area stretching roughly from Bellingham, Washington to Salem, Oregon. In the Portland-Vancouver metropolitan area, the Centralia Plant=s contribution to the annual average NO_x concentration was about 0.2 $\mu g/m^3$ (0.0001 ppm), while the maximum 24-hour concentration was estimated to be about 3 $\mu g/m^3$ (0.0016 ppm) with no additional emission controls on the plant. For the Seattle-Tacoma urban area, the plant=s contribution to the annual average NO_x concentration was about 0.4 to 0.6 $\mu g/m^3$ (< 0.0003 ppm), while the peak 24-hour concentration was estimated to be about 4 $\mu g/m^3$ (0.002 ppm) with no additional emission controls on the Plant (Ref. 40, App. B).

4.1.8 Acid Deposition

Nitrogen deposited on the land contributes to the land becoming nitrogen-saturated causing more available nitrogen to run off into nearby waters leading to increased acidification of both the soils and waters. Increased nitrate nitrogen removes calcium and magnesium from the soil. After calcium and magnesium in the soil has been depleted, aluminum begins to move into nearby waters with the fixed nitrogen. Aluminum is toxic to many aquatic species. Increased levels of fixed nitrogen on land can create nutrient imbalances in trees leading to reduced photosynthesis and changed species composition (Ref. 44).

Studies provide a strong basis for concern that the long-term integrity of lakes in the Cascades could be affected if atmospheric deposition contains pollutants. It is generally accepted that surface waters with chemical characteristics like those in the Cascades are indicative of extremely sensitive systems, but as yet these lakes do not exhibit any signs of acidification from atmospheric deposition (Ref. 13, p. 19, 24; Ref. 15, pp. 58 and 84; and Ref. 16, p. 35).

Modeling of nitrogen deposition using the CALMET/CALPUFF modeling system was conducted by Vimont of NPS. Based solely on current emission levels of NO_x from the Centralia Plant without the effect of any other sources, the model predicted a peak nitrogen deposition rate in Mount Rainier National Park of 0.055 kg/ha/yr at the northwest corner of the park. This same level of nitrogen deposition was also predicted to occur in the Clearwater Wilderness, site of acid-sensitive lakes. The maximum nitrogen deposition rate due to plant NO_x emissions occurs nearby the Plant and is about 0.13 to 0.15 kg/ha/yr (Ref. 45).

Critical loads for nitrogen deposition in national parks of the Pacific Northwest are suspected to be considerably lower than estimates cited for forests of Europe and the northeastern U.S. (7 to 10 kg N/ha/yr). An interim value of 5 kg N/ha/yr is suggested for the protection of aquatic resources against chronic acidification. A lower value of critical nitrogen (N) loading may be necessary to protect these resources from episodic acidification (Ref. 4, p. xv).

Forest ecosystems in the Northwest may be more sensitive to smaller additions of N than forests in other regions because forests in the northwest have shallow soils and snowmelt is an important component of runoff. Low levels of N deposition may have important influences on the species composition of plant communities via subtle alterations in plant competition. Currently, the most important form of N deposition to these forests may be acidic components in fog (Ref. 4, p. xvi).

The La Grande, Washington NADP/NTN site has measured nitrate concentrations similar to those observed at North Cascades National Park but twice as large as those observed in the central Oregon Cascades at H. J. Andrews Experimental Forest (Ref. 4, p. 102).

4.2 Availability of Additional NO_x Controls

Combustion process modifications reduce emissions of NO_x by limiting the amount produced during the combustion process. This is accomplished through operational modifications such as boiler tuning and low excess air operation, and by design modifications such as low NO_x combustion firing systems, advanced combustion processes, gas co-firing, gas conversion, and reburning.

Flue gas recirculation primarily counteracts formation of thermal NO_x, and is generally ineffective on large coal-fired utility boilers where NO_x emissions originate from conversion of fuel-bound nitrogen. Fuel NO_x is formed as nitrogen contained in the coal is driven off in the volatilization process and comes in contact with oxygen in the combustion air. This NO_x formation reaction occurs on a time scale comparable to the energy release reactions during combustion.

In tangential boilers such as those at Centralia Plant, the fuel and air are injected through vertically stacked nozzles in the boiler corners creating fuel-rich regions in an overall fuel-lean environment.

Fuel NO_x formation can be suppressed by the delayed mixing of fuel and air, allowing fuel-nitrogen compounds a greater residence time in fuel-rich conditions.

Good operating practices can be employed with any technology-based NO_x control method. Specific guidelines issued to Plant operators to minimize NO_x emissions include the following (Ref. 43):

(a)Use of specified excess air levels that are defined by the boiler demand.

(b)Operating with the top level coal mill out of service when the coal quality and availability of other coal mills allows. Keep the pulverizer grouping together whenever possible to minimize separation of fuel input regions.

(c)Manual operation of the auxiliary air dampers on the top two mills will simulate overfire air by introducing more of the excess air in the upper region of the furnace.

(d)Use of soot blowers to clean the boiler furnace walls thereby reducing temperature at the walls.

(e)Burner tilts are operated in the horizontal position to reduce combustion temperature which lowers NO_x formation.

As demonstrated in '4.1.1, good operating practices are currently used to enable the Centralia Plant to meet the Acid Rain Program early election Phase I limit of 0.45 lb NO_x/MBtu. Some of these practices will be inherent in the NO_x emission control technologies once retrofit to the plant. The performance of the Centralia Plant Units #1 and #2 using good operating practices for low NO_x provides insight into how well the present boiler configuration can be operated. Recent performance shows that the NO_x emission rate at low load is not appreciably higher than at full load, although low load conditions do cause greater variability in the NO_x rate. The recent operation of the plant, and especially since the middle of 1996 when the operators began actively adjusting boiler conditions for low-NO_x combustion, shows that NO_x emissions at low load have been both lower and higher than NO_x emissions at high load, as the following values for average hourly NO_x emission rate indicate.

	Quarter Averages (lb/MBtu)	
Calendar Qtr.	Load < 40% capacity*	Load > 85% capacity*
4th qtr. 1996	(only 1 hr. all qtr.)	0.41
1st qtr. 1997	0.42	0.37
2nd qtr. 1997	0.32	0.38
3rd qtr. 1997	0.34	0.38

* Categories are lowest and highest 15% of rated load; 25% capacity is approximate minimum gross load.

The data indicate that the low load NO_x emission rate is not appreciably higher than the high-load NO_x emission rate. In fact, for some time periods, the average NO_x emission rate at low loads (< 40% of capacity) is lower than the average rate at high loads (> 85% of capacity). For longer averaging periods, such as an annual average standard, the extreme values in short-term variations will offset over the averaging period.

Data from the first half of 1997 indicate that the minimum NO_x emission rate (mass of emissions per unit of heat input) occurs at approximately half to 60% load, while the NO_x rate increases as load is reduced to its operational minimum of about 180 to 200 MW (gross) or as load increases to full output. Variability in hourly NO_x rate often encompasses a range of 0.20 lb/MBtu between typical low and high values at any given operating load, but the monthly averages are stable, reflecting operating techniques, coal quality, and seasonal variation in load. In Figure 4-1, the monthly average NO_x emission rates for both units are shown along with the 12-month average of 0.38 lb/MBtu for the July 1996 through June 1997 period. Near continuous high-load operations occurred from late September through December, while large load fluctuations have been the norm throughout the 2nd quarter of 1997 (Ref. 51). Additional NO_x rate data are provided in Appendix E to this document.

The available NO_x control technologies for achieving reductions in the average NO_x emission rate include boiler tuning, fuel and air replacement, low-NO_x burners with various degrees of staging, use of natural gas, selective catalytic reduction, and selective non-catalytic reduction. These technologies are discussed, in turn, below.

Boiler tuning options involve adjusting operational variables such as excess air levels, burner tilts, coal mills in service, and primary air flows. Operation at low excess air levels minimizes the formation of NO_x. Ease of implementation is an advantage of boiler tuning, making it a first step prior to using more complex NO_x reduction methods. Another form of tuning is an expert system which typically employs neural networks or regression analysis to optimize performance within the available hardware configuration.

Fuel and air tip replacement provides NO_x reductions through alterations in the fuel and air mixing regime. This measure can also be used as a supplement with other methods of emission reduction.

Low NO_x burners (LNB) provide localized staging of combustion air and are often combined with the bulk-furnace air staging feature of overfire air. One particular design of LNB known as Low-NOx Concentric Firing System (LNCFS) was specifically developed for retrofitting to tangentially-fired furnaces. The coal and air nozzles are arrayed to produce two concentric combustion regions: a fuel-rich inner zone containing most of the coal, and a surrounding fuel-lean outer zone containing the secondary combustion air. This configuration produces a stable flame front and an oxygen-deficient core which allow coal-bound nitrogen to evolve as nitrogen gas (N_2) thereby reducing NO_x formation. The secondary combustion air is directed towards the walls of the boiler to provide oxygen-rich conditions that prevent slagging and corrosion (Ref. 50, p. 7).

Available LNCFS technology for tangential units is comprised of multiple levels of staging in which each additional stage provides additional NO_x reduction. In the first level, close-coupled over fire air (CCOFA) compartments provide vertical separation of the fuel and a portion of the combustion air to create staging conditions in the furnace. One or more of the coal nozzles is relocated lower along the boiler wall to create the necessary vertical separation. In Level II, a separate overfire air (SOFA) wind box provides increased diversion of secondary combustion air away from the main burner zone. SOFA modification includes new ducting and air inlet openings in the boiler furnace corners on tangential units. Sufficient height above the present top registers exist at the Centralia Plant units to accommodate such a modification. Level III low NO_x staging uses a combination of CCOFA and SOFA registers to achieve a greater degree of combustion air staging in the furnace, and hence NO_x reduction (Ref. 29, pp. 16-18).

Figure 4-1

The EPA RACT/BACT/LAER Clearinghouse contains 55 coal-fired boiler units for which RACT determinations were made in 1994 and 1995. Forty of these units had some type of low NO_x combustion system installed to meet RACT. These included 29 units now equipped with low NO_x burners with SOFA, 5 units with low NO_x burners including both CCOFA and SOFA, and 6 units with low NO_x burners alone. The RACT list of 1994-1995 permits includes 21 units between 2,340 and 8,010 MBtu/hr heat input (each Centralia unit is rated at 7,015 MBtu/hr) all of which are equipped with low NO_x burners accompanied by SOFA while three units include CCOFA in addition to SOFA (Ref. 47).

Supplemental or complete conversion to use of natural gas includes several technologies for reducing NO_x emissions. Gas co-firing displaces nitrogen in the fuel by substituting natural gas for a portion of the coal but further reduction of NO_x requires a modification to the air and fuel flow characteristics according to EPRI studies. Gas conversion has been implemented for previous oil-fired units, but at only one coal-fired unit, the 448 MW Kansas P&L Lawrence 5 tangential unit which has alternating levels of natural gas and coal nozzles that allow for full load operation with either fuel or co-firing with both coal and gas (Ref. 48, p. 5.68).

In natural gas reburn technology, gas is injected above the main burner zone following primary combustion with coal which occurs under fuel-lean conditions. The gas is injected above the burners providing a slightly fuel-rich reburning zone, then the remaining combustion air is injected to complete combustion. Residence time in the reburn zone is a controlling factor in reducing NO_x emissions. Gas reburning systems involve gas piping, some simple gas injectors, and overfire air ports. The 71 MW tangential coal-fired Hennepin Unit 1 owned and operated by Illinois Power was retrofitted with gas reburn and sorbent injection in 1991 and then tested under a variety of operating conditions. During parametric testing, gas reburn was capable of achieving the process goal of 60% NO_x reduction (Ref. 49). Gas reburn was installed on the tangentially-fired 105 MW Greenidge Unit 4 operated by New York State Electric & Gas Corp. in early 1996 (Ref. 46). These systems are presently in commercial use only on small boilers.

Selective Catalytic Reduction (SCR) technologies use a titanium or vanadium catalyst and injection of ammonia to convert the flue gas NO_x to molecular nitrogen (N_2) and water. These add-on emission control systems have been used on similar sized boilers on European coal-fired utility boilers. Until recently, use of SCR in the U.S was limited mainly to gas-turbine cogeneration facilities (Ref. 59, p. 2-3). An SCR system on the Centralia Plant boilers would be the largest installation of its type in the U.S. (Ref. 29, p. 20-21).

Selective Non-Catalytic Reduction (SNCR) systems convert NO_x to its elemental components by injecting either urea or ammonia under high temperature conditions. Units up to 160 MW in size have been retrofitted with SNCR systems throughout the U.S. Good mixing of the reagent throughout the boiler cross-section is a key factor in the success of this type of control technology. Scale up of the system components to boilers the size of Centralia Plant is one potential problem with this system. Urea does not have the handling and storage safety issues associated with use of ammonia, but costs more for the same degree of NO_x removal (Ref. 42). SNCR has been combined with low-NO_x burners at the Public Service Company of Colorado Arapahoe Station to achieve large reductions from a baseline NO_x level of 1.10 lb/MBtu, considerably above the Centralia Plant baseline.

Combined SO_2/NO_x technologies are currently under development to provide an alternative to the use of flue gas desulfurization (FGD) and SCR in series which has experienced reduced reliability, particularly with high sulfur coals. Three processes rated higher than FGD/SCR when evaluated for new plants. These combined processes are absorption/regeneration, catalytic reduction/oxidation, and the $SO_x/NO_x/RO_x$ Box process by Babcock & Wilcox. Experience to date shows that all combined processes have higher capital costs than FGD/SCR due to the complexity of different process units.

Construction time lines depend on the control technology implemented. For a low NO_x burner system, the outage and retrofit of the boilers is envisioned to begin on March 1, 2001 for the first unit and on March 1, 2002 for the other unit. No definite outage schedule has been established by the Centralia Plant for these future years yet, since a coordinated outage schedule depends on installation of SO_2 emission control equipment, the electric power market, availability of hydropower resources, and outages of other generating plants in the system that supplies the Centralia Plant owner utilities. Traditionally, outages at Centralia Plant occur during the second calendar quarter of the year when hydroelectric power is abundant in the region. However, an outage at the end of the third quarter is possible for installation of low NO_x burner modifications and potential FGD system tie-in (Ref.42).

4.3 Emission Reduction to be Achieved by Additional NO_x Controls

4.3.1 Effectiveness of NO_x Control Options

Available control technologies are capable of reducing NO_x emissions by anywhere from 5% to 70%. The effectiveness of different controls can be logically grouped into three categories. The three least expensive options achieve emission reductions of less than 10% over the calendar year 1996 baseline emission level of 0.44 lb/MBtu. The second category of options includes several low NO_x burner (LNB) alternatives with different stages of overfire air and is capable of delivering NO_x reductions of 27% to 43% over the baseline emission rate. The final category is an option with two cost variations that are both capable of 70% NO_x reduction from the baseline emission rate of 0.44 lb/MBtu, and are also the most expensive options in terms of total capital cost. These NO_x control options are ranked below according to achievable emission rates. The controlled NO_x emissions are presented as a range of annual average values based on vendor quotes for achievable controlled NO_x emission rates, published literature, and the boiler design at Centralia Plant Units #1 and #2 (Ref. 29, App. E, p. 3-16).

Emission Reduction Technology	NO_x Emission Rate (lb/MBtu)	NO_x Reduction (Percent)
Boiler Tuning	0.40 to 0.44	0 to 9
Fuel and Air Tip Replacement	0.40 to 0.44	0 to 9
LNB & Close Coupled Overfire Air (CCOFA)	0.38 to 0.42	5 to 14
LNB & Separated Overfire Air (SOFA)	0.30 to 0.34	23 to 32
Selective Noncatalytic Reduction (SNCR)	0.29 to 0.33	25 to 34
LNB with CCOFA plus SOFA	0.26 to 0.30	32 to 41
Hybrid (SNCR plus air heater SCR)	0.24 to 0.28	36 to 46
Gas Reburning	0.20 to 0.25	43 to 55
Selective Catalytic Reduction (SCR)	0.10 to 0.15	66 to 77

The evaluation of technologies above expresses the emission reductions relative to a baseline level of 0.44 lb/MBtu. If one starts with the plant=s potential to emit--or maximum capacity to emit NO_x based on its operation and design--then the difference in emissions, compared to the achievable emissions with a control technology in place, represents the maximum emissions reduced by the application of controls. The Centralia Plant=s potential to emit (PTE) is calculated based on the highest recorded concentration of NO_x, 0.61 lb/MBtu, measured during stack tests in the last eight years, and full capacity operation. Since the plant typically operates at 70% capacity factor (CF), the maximum possible emissions at 70% CF is less than PTE, and is determined to be 26,239 tons NO_x/yr (Ref. 42). Using the value of maximum possible emissions at 70% CF as a reference point, the control efficiencies of the available candidate technologies will be correspondingly higher. The quantity of emissions reduced by each of the control technologies is presented below with reference to both the 1996 baseline and 70% maximum value. For each technology, the midpoint of the emission rate range shown in the previous list above is considered the best estimate of the annual emission rate (except for gas reburning, where the upper end of the range is assumed due to large uncertainties in retrofitting gas reburn to the Plant) (Ref. 29, App. E, p. 3-16). Annual expected emissions in total tons, and then emissions reduced, are determined from the annual emission rate. These NO_x reduction values will be carried forward throughout this analysis.

	NO_x Emission	NO_x Reduction (tons/yr)	
Emission Reduction Technology	Rate (lb/MBtu)	vs. Baseline	vs.Max
Boiler Tuning	0.42	861	8,173
Fuel and Air Tip Replacement	0.42	861	8,173
LNB & Close Coupled Overfire Air (CCOFA)	0.40	1,721	9,033
LNB & Separated Overfire Air (SOFA)	0.32	5,162	12,474
Selective Noncatalytic Reduction (SNCR)	0.31	5,592	12,905
LNB with CCOFA plus SOFA	0.28	6,883	14,195
Hybrid (SNCR plus air heater SCR)	0.26	7,743	15,055
Gas Reburning	0.25	8,173	15,486
Selective Catalytic Reduction (SCR)	0.13	13,335	20,647

NO_x emission reductions are based on middle of emission rate range except for gas reburn.

The NO_x emission rates presented above represent how the control technologies are specified to perform. The estimates of control effectiveness for CCOFA, SOFA, and CCOFA plus SOFA are based on equipment vendor information, performance quotes which consider the Centralia Plant=s configuration, published data, and experience of PacifiCorp's contractor Stone & Webster with tangentially-fired coal utility units. Overfire air limits NO_x emissions by: (1) suppressing thermal NO_x formation by extending the combustion process resulting in cooler flame temperature, and (2) suppressing fuel NO_x formation by lowering the concentration of air in the burner zone where volatile fuel nitrogen is evolved (Ref. 48, p. 5-8).

Tangentially-fired boilers ranging in size from 200 to 446 MW equipped with LNB configured to supply CCOFA (Level 1) reported long-term controlled NO_x levels of 0.35 to 0.40 lb/MBtu, a reduction of 35% to 45%. The uncontrolled emissions of these units firing bituminous coal ranged from 0.62 to 0.64 lb/MBtu, considerably above the typical historical long-term NO_x rates observed at the Centralia Plant (Ref. 48, pp. 5.34-5.41).

Performance of LNB with overfire air when retrofit to tangentially-fired boilers burning bituminous or subbituminous coal has reduced NO_x emissions by 25% to 60% depending on the initial uncontrolled emission rate. The Cherokee 4 350 MW unit equipped with LNB Level II (includes

SOFA) and burning bituminous coal achieved short-term controlled NO_x rates of 0.28 to 0.33 lb/MBtu at full- and low-load, respectively. Over 18 months of operation, the Level II system reduced the NO_x emission rate from Cherokee 4 to approximately 0.30 lb/MBtu across its load range (Ref. 60, p. 1500). The 200 MW Lansing Smith 2 boiler with SOFA installed achieved long-term NO_x rates of 0.40 to 0.41 lb/MBtu at mid- and full-load, respectively, burning bituminous coal. The 448 MW Lawrence 5 tangential unit equipped with LNB and SOFA achieved a short-term level of 0.25 lb/MBtu and a long-term NO_x emission rate of 0.19 lb/MBtu at half load firing subbituminous coal. The 165 MW Valmont 5 unit firing bituminous coal was tested using SOFA controls which indicated a NO_x rate of 0.32 lb/MBtu at full-load (52% reduction) and 0.75 lb/MBtu (27% reduction) at low-load, both for a period of several hours (Ref. 48, pp. 5.46-5.54). However, over the first half of 1997, the Valmont 5 unit has achieved an average NO_x rate of 0.29 lb/MBtu (Ref. 74).

LNB systems including both SOFA and CCOFA have demonstrated NO_x emission reductions of 30% to 65% when retrofit to tangentially-fired boilers burning bituminous and/or subbituminous coal. With Level III installed, the Lansing Smith 2 unit operated long term at 0.34 to 0.37 lb/MBtu, and achieved a short-term controlled NO_x rate of 0.36 lb/MBtu at full-load conditions. The full-load NO_x reduction for SOFA and CCOFA technology on Lansing Smith 2 was approximately 50% burning eastern bituminous coal, which typically produces higher uncontrolled emission rates than the western subbituminous coal burned at Centralia Plant. Initial testing on the 620 MW Labadie 4 unit burning a blend of bituminous and subbituminous coal resulted in short-term NO_x emissions of 0.45 lb/MBtu across the load range compared to uncontrolled emissions of 0.54 to 0.69 lb/MBtu (Ref. 48, pp. 5.40-5.52). Since completing initial tuning, Labadie 4 has achieved an annual average of 0.22 lb/MBtu in 1996, or about a 65% NO_x reduction, and a six-month average of 0.21 lb/MBtu in the first half of 1997 (Ref. 74). Labadie 4 is a tangentially fired, dry bottom, coal-fired boiler, manufactured by Combustion Engineering (CE) similar to Centralia Plant, and constructed in 1973. All four units at the Labadie Plant have been retrofitted with ABB low NO_x (level III) burners, and achieve consistently low NO_x emission levels (0.19 to 0.22 lb/MBtu). All coal is supplied from the Powder River Basin in Wyoming.

The similarities of the Labadie and Centralia Plants deserve a closer examination of the differences in the plants to understand how results at Labadie may be applied to potential retrofit of low NO_x Level III burners on the boilers at the Centralia Plant. A divided furnace, such as at the Centralia Plant units, is more sensitive to operation at low load because its dynamics of mixing are more complicated. However, more levels of coal nozzles (8 at Centralia vs. 6 at Labadie) mean better control of fuel and air and therefore relatively easier control of the NO_x emission rate at low load. Larger burner spacing at Labadie may increase the level of combustion staging, but burner spacing is only a concern for thermally-produced NO_x, and has little impact on fuel-bound NO_x. At the Centralia Plant, the fuel NO_x accounts for 60 to 80% of the total NO_x formed during coal combustion in the boilers. The type of fuel tends to have a greater influence on NO_x reduction performance than spacing of burners in the furnace according to ABB. Reductions in NO_x are easier to attain with subbituminous coal (Centralia) than with bituminous coal (burned at Labadie in combination with subbituminous) because the former's constituents volatilize more quickly than those of bituminous coal. On balance, the differences between unit design and operational factors favor better expected potential NO_x performance at Centralia Plant as much as better performance at Labadie Plant (Ref. 80).

Public Service Electric & Gas Company of New Jersey tested a selective noncatalytic reduction (SNCR) system, an in-duct selective catalytic reduction (SCR) system, and a hybrid (SNCR plus SCR) system at its Mercer Generating Station. This station consists of twin 321 MW wet-bottomed, wall burner, bituminous coal-fired units. The SNCR demonstration program reduced NO_x emissions by 37% while maintaining an NH_3 slip of 4 ppm. Use of In-Duct SCR resulted in NO_x emission reductions of 60% to 95% while maintaining NH_3 slip to less than 10 ppm upstream of an air heater and less than 5 ppm at the air heater outlet. Testing of the hybrid SNCR/SCR system produced NOx reductions comparable to the In-Duct SCR with air heater (Ref. 75). Data do not appear to be available for these systems retrofit to a tangentially-fired boiler.

Data from a natural gas reburn application on a tangentially-fired boiler (Hennepin 1, 75 MW) indicate NO_x emissions averaged 0.23 lb/MBtu, or a 60% reduction during operation at 53 to 100 percent of full load. The 448 MW Lawrence 5 tangentially-fired unit achieved a controlled NO_x emission rate of 0.15 to 0.18 lb/MBtu while co-firing with 10 percent natural gas, which reduced NO_x emissions by 20% to 30% over the level resulting from low-NO_x burner use alone (Ref. 48). The 105 MW Greenidge Unit 4 operated by New York State Electric & Gas achieved a NO_x emission rate of 0.29 lb/MBtu, a 53% reduction over uncontrolled levels, with only 15% of the heat input provided by gas through use of gas injectors rather than recirculation (Ref. 46).

An emission reduction option that does not meet the eventual Acid Rain Program Phase II limit may still be considered a temporary option to meet the early election Phase I limit effective in 1997. The costs of compliance and present emission levels will affect whether a particular facility may select staged modifications to meet Phase II emission limits or comply with the Acid Rain limits following one installation of emission controls (Ref. 42).

Operating margin over stated levels of effectiveness is needed according to PacifiCorp due to the CEMS data and missing data substitution methodology, dispatch of the units, fuel quality, and equipment (Ref. 42, item 22).

(a)CEMS - A comparison of 1996 measured CEMS data and reported data indicates a 3.5% operating margin is necessary because of the inherent differences between these quantities.

(b)Dispatch - A low NO_x burner vendor estimates NO_x rates will increase at loads below 50% for the different levels of NO_x control as follows:

LNB with CCOFA	0.05 lb/MBtu	12.5% increase over predicted performance
LNB with SOFA	0.07 lb/MBtu	22% increase over predicted performance
LNB w/ CCOFA+SOFA	0.08 lb/MBtu	29% increase over predicted performance

As the averaging period is reduced from annually to quarterly, monthly, or daily, the percent of time a unit operates at reduced load increases. The need for operating margin with a shorter averaging time period increases to compensate for the increased time at reduced load.

(c)Fuel quality - When fuel quality is poorer than normal, the boiler is typically operated at higher excess air levels to reduce the effects of slagging. NO_x exhaust concentrations rise with higher excess air, and will increase still further if slag buildup is excessive so that the boiler walls cannot be kept clean. Total effect of fuel quality on NO_x emission rate can be as high as 0.05 lb/MBtu.

(d)Equipment - Failure of certain equipment may cause increases in NO_x emissions. However, no operating margin is contemplated to account for equipment malfunction since such occurrence may be prevented or minimized through good maintenance by the Plant operator.

Currently, the emission rate of NO_x per unit heat energy input to the boilers (e.g., lb/MBtu) at the Centralia Plant varies considerably on an hourly basis especially at low electric load. Low NO_x burner technologies will reduce the magnitude of the average and peak emission rates, but will not counteract the short-term variation in NO_x emission rate which occur with load variations. Total NO_x emissions (e.g., tons/hr) vary directly with load, reaching a maximum at full load and decreasing with reduced load and energy input. However, the NO_x rate (lb/MBtu) is about the same or slightly higher at low load compared to full boiler output. The NO_x rate is at its minimum value at approximately half to 60% load, and the amount of increase at both low and high load depends on coal quality, load changes, and the boiler operation techniques. Observed NO_x rates during 1996 and 1997 at low load are not substantially higher, on average, than the rates at full load despite the greater variability which occurs at low load. Exceptions to this general trend were noted in March 1996 and January 1997. During the first half of 1997, the average NO_x rate for both Centralia Plant units, combined, was 0.35 lb/MBtu (Ref. 51). This period was marked by frequent load fluctuations between minimum and near full capacity which allowed for operation of the boiler in a "pseudo-CCOFA" mode where the top coal mills are taken out of service and secondary combustion air supplied through the top air nozzles at low load conditions.

In the health impacts study by J. Samet et al. and K. Winges (Ref. 40), the increase in ambient NO_x concentration due to Centralia Plant emissions was predicted throughout western Washington and northwestern Oregon using the CALPUFF modeling system. For the controlled emission scenario, the model used a 30% reduction in NO_x emissions relative to the projected baseline level without controls on the Plant. The emission scenarios were provided to the study authors by PacifiCorp to assess the magnitude of and change in health effects throughout the region from the addition of emission controls at the Centralia Plant.

The Pennsylvania Department of Environmental Protection (PaDEP) has completed since 1993 RACT determinations for 22 tangential coal-fired utility boilers ranging in size from 80 to 893 MW. This set includes 10 units with capacity greater than 300 MW up to 893 MW for which 30-day rolling average emission limits were established. Presumptive RACT is defined by PaDEP for coal-fired combustion units with input heat rate greater than 100 million Btu/hr to be the installation and operation of low NO_x burners with separate overfire air. The emission limit established for most of these larger units is 0.45 lb/MBtu, on a 30-day rolling average, although PaDEP may revise the allowable emission rates based on a minimum of 6 months of continuous monitoring data (Ref. 52). Unfortunately, this provision can be a reverse incentive encouraging operators to not reduce emissions as low as the technology is capable of performing in order to maintain the originally established limit.

The large capacity tangentially-fired boilers in Pennsylvania for which 30-day rolling averages were established burn eastern bituminous coal which tends to produce higher levels of NO_x than the coal burned at the Centralia Plant. The emission reductions achieved at 10 units by the use of LNB Level III relative to the 1990 Acid Rain Program baseline NO_x emissions are summarized below. The current NO_x emission rate data are 6-month average values for the first half of 1997 (Ref. 74). The range of NO_x rate reductions compared to uncontrolled emissions is larger than the 32% to 41% reduction projected for the Centralia Plant from installation of LNB Level III.

Unit Designation	Capacity (MW)	1997 6-mo. Avg. NO_x (lb/MBtu)	Emission Reduction From 1990 (%)
GPU Genco Keystone 1	8930.42		39%
GPU Genco Keystone 2	8930.39		47%
GPU Genco Conemaugh 1	893	0.41	39%
GPU Genco Conemaugh 2	893	0.39	45%
Penn P&L Montour 1	765	0.43	61%
Penn P&L Montour 2	750	0.42	62%
Penn P&L Brunner Island 3	745	0.42	49%
Penn P&L Brunner Island 2	390	0.36	49%
Penn P&L Brunner Island 1	334	0.36	45%
PECO Energy Eddystone 2	302	0.31	45%

The Northeast States for Coordinated Air Use Management (NESCAUM) Stationary Source Review Committee recommended a limit of 0.38 lb NO_x/MBtu, 24-hour average, for tangentially-fired coal boilers in its Phase I of emission reductions. The Committee considers this limit to be among those achievable without the use of post-combustion add-on control equipment, such as SCR or SNCR. Daily average values are considerably larger than annual limits due to the short-term variability in the NO_x emission rate. In Phase II of the NESCAUM strategy to reduce emissions from stationary combustion sources of at least 250 MBtu/hr heat input, a limit of 0.20 lb NO_x/MBtu, 24-hour average, will become effective in May 1999 and a limit of 0.15 lb NO_x/MBtu, 24-hour average, will become effective in May 2003 within the worst non-attainment areas of the NESCAUM region (Ref. 53).

The EPA Acid Rain Program provided data for other tangentially-fired boilers between 500 and 850 MW capacity with retrofit low-NO_x burners installed. The operating record shows the annual NO_x emission reduction for these 14 units varied from 17 to 71% in 1995 and 1996, depending on the initial emission rate prior to controls, the level of staging installed with the system retrofit, and the type of coal burned in the boiler. Based on data from the five units west of the Mississippi River, which more closely represent the subbituminous coal burned at Centralia Plant than the units in the eastern U.S., the Acid Rain Division derived an absolute NO_x emission rate of 0.27 lb/MBtu. A comparison of the improvement associated with low-NO_x Level III over low-NO_x Level II, and use of 1995-96 Centralia Plant data results in an EPA recommended NO_x emission limit range of 0.23 to 0.37 lb/MBtu.

4.3.2 Effect of Options on Other Air Pollutants

Combined NO_x/SO_2 control systems are under development at the present time. These technologies are not considered to be commercially available, and so are not considered in further detail in this analysis. Therefore, NO_x emission control will not appreciably affect emissions of SO_2, except for the natural gas reburn option. Combustion of gas, which contains very little sulfur, in place of approximately 10 percent by heat input of the primary fuel coal is estimated to reduce SO_2 emissions by about 10 percent (Ref. 29, p. 108).

Low NO_x combustion modifications with staged injection of combustion air cause efficiency losses due to increases in unburned carbon. The specific boiler and fuel, and the retrofits made to the boiler to accommodate overfire air ports will affect the unburned carbon efficiency loss. Present levels of unburned carbon in the fly ash from Centralia Plant are less than 0.2%. Low NO_x combustion equipment could be retrofit with guarantees that limit unburned carbon to less than

1.0% at both units according to vendors (Ref. 29, App. E, p. 3-2). The unburned carbon increases the resistivity of ash which decreases the PM collection efficiency slightly in the ESPs. Effects on PM of the NO_x control technologies are summarized below:

NO_x Emission Reduction Technology	Particulate Matter
Boiler Tuning/Fuel and Air Tip	No change
LNB with Close Coupled Overfire Air (CCOFA)	Small increase possible from UBC in ash
LNB with Separated Overfire Air (SOFA)	Small increase possible from UBC in ash
Selective Noncatalytic Reduction (SNCR)	No change
LNB with CCOFA plus SOFA	Small increase possible from UBC in ash
Hybrid (SNCR plus air heater SCR)	No change
Natural Gas Reburn	Small decrease
Selective Catalytic Reduction (SCR)	No change

Carbon monoxide (CO) and NO_x emissions from coal combustion can be reduced simultaneously only with technical advances at considerable cost as improvements in combustion efficiency and excess air management reach their optimum levels. Adjustments in boiler operating conditions to reduce NO_x will result in CO emission increases. Low NO_x system vendors have indicated any guarantee for CO emissions must allow for an approximate doubling of emissions over present levels, which range up to about 50 ppm. Low NO_x vendor ABB indicates it will guarantee CO emissions for a CCOFA system to remain less than 50 ppm above a baseline value, for a SOFA system less than 75 ppm above a baseline value, and for a combined SOFA and CCOFA (Level III) system less than 75 ppm above the baseline value (Ref. 76). The expected effect of NO_x reduction technologies on CO emissions is summarized below for each of the candidate NO_x technologies.

The NO_x technologies will not appreciably change the emission of organic hazardous air pollutants or toxic air pollutants. Metals and mercury contained in the coal will not be removed by any of the NO_x reduction technologies. The only effect on emission of toxics is the potential for ammonia slip from the post-combustion emission reduction systems that use either ammonia or urea as a reagent; a summary of these effects is shown below (Ref. 29, p. 108):

NO_x Emission Reduction Technology	Carbon Monoxide	Toxics/HAPs
Boiler Tuning/Fuel and Air Tip	No change	No change
LNB with CCOFA	20 ppm (50 ppm)[a] increase	No change
LNB with SOFA	35 ppm (75 ppm)[a] increase	No change
Selective Noncatalytic Reduction (SNCR)	No change	NH_3, 10 ppm
LNB with CCOFA plus SOFA	35 ppm (75 ppm)[a] increase	No change
Hybrid (SNCR plus air heater SCR)	No change	NH_3, 5 ppm
Natural Gas Reburn	No change	No change
Selective Catalytic Reduction (SCR)	No change	NH_3, 5 ppm

[a] Expected increase followed by guaranteed maximum level of increase in parentheses.

Installation of low NO_x burners with CCOFA and/or SOFA could potentially double total emissions of CO from about 1,500 tons/yr in an average operating year to about 3,000 tons/yr. An increase of this magnitude would normally trigger the Prevention of Significant Deterioration (PSD) permit program for the CO emissions increase, except in this instance, the CO increase results from a pollution control project as defined in 40 CFR 51 and does not trigger PSD requirements. The need for achieving substantial reductions in NO_x emissions greatly outweighs the significance of the CO emissions increase.

Use of ammonia and urea can increase emissions of nitrous oxide (N_2O), a stable form of nitrogen that acts as a greenhouse gas in the upper atmosphere. Although both chemicals increase N_2O, the increases associated with ammonia are much lower than those obtained from urea in SNCR systems (Ref. 54).

4.3.3 Other Environmental Impacts

4.3.3.1 Water Quality

For the post-combustion technology options, the storage and use of ammonia and urea and its absorption in fly ash may affect waste water at the plant. Ammonia in flue gas may be collected in wet scrubber blowdown and affect waste water quality. Limitations on discharges of ammonia might need to be incorporated into the NPDES permit. All other NO_x reduction technologies are not expected to change the characteristics of waste water discharges. About half of the discharged water is runoff from precipitation (Ref. 29, p. 109).

4.3.3.2 Solid and Hazardous Waste

Coal combustion produces between 500,000 and 800,000 tons of coal ash each year depending on the quantity of coal consumed and its ash content. About 250,000 to 300,000 tons/yr is sold as an additive to concrete, while the balance is returned to the CMC mine for backfill. Evaluation of fly ash samples collected in 1991, 1993, and 1994, and bottom ash samples taken in 1992, 1993, and 1994 indicate that the equivalent concentration of constituents, computed per WAC 173-303-084(5)(b), is well below the dangerous waste and extremely hazardous waste thresholds. Therefore, neither type of ash is designated as a dangerous or extremely hazardous waste in accordance with WAC 173-303 (Ref. 29, Appendix J, p. 3 & Attachment B).

At levels of 7 ppm to 10 ppm ammonia in the flue gas, the ash would contain 700 to 1,000 ppm ammonia, or an equivalent concentration of 0.0010% as defined in the dangerous waste regulations. With installation of a post-combustion SNCR, SCR, or Hybrid system, the ash would more likely contain 100 to 300 ppm ammonia, but could increase in an upset condition and exceed 0.0010%, the threshold for dangerous waste designation (Ref. 29, Appendix J, p.5). Costs for disposing and managing a dangerous waste escalate significantly compared to those for a solid waste. Impacts of the various NO_x control technologies on solid and hazardous wastes are summarized below (Ref. 29, p. 112):

NO_x Technology	Solid Waste	Hazardous Waste
Tuning/Fuel & Air Tip	No change	No change
LNB with CCOFA	Fly ash sales reduced if UBC too high	No change
LNB with SOFA	Fly ash sales reduced if UBC too high	No change
SNCR	Possible NH_3 contamination	NH_3 handling; fly ash toxicity
LNB w/ CCOFA & SOFA	Fly ash sales reduced if UBC too high	No change
Hybrid SNCR	Possible NH_3 contamination	NH_3 handling; fly ash toxicity
Natural Gas Reburn	Fly ash quantity reduced since less coal	No change
SCR	Possible NH_3 contamination	NH_3 handling; fly ash toxicity

UBC = unburned carbon

Emission control technologies that cause significant impacts from discharge of other air pollutants or of cross-media pollutants would suffer accordingly in evaluation of options suitable for use. No such fatal flaw has been identified for any of these NO_x reduction technologies since any impacts as identified above are considered minor relative to the NO_x emission reductions that they can yield.

4.4 Impact of Additional NO_x Controls on Air Quality

4.4.1 Ambient NO_x and Nitrate

The projected decrease in NO_x emissions out to the year 2006 in the western Washington emission inventory is largely due to real and projected reductions at the Centralia Power Plant. On road motor vehicles comprise about 65% of the NO_x inventory, so overall benefit is modest (Ref. 30, p. 15).

Modeled increments to ambient concentrations due to the Centralia Plant were predicted in the 1997 study "An Assessment of the Health Risks Due to Air Emissions from the Centralia Power Plant" by Jonathan Samet et al. of the Johns Hopkins University Department of Epidemiology and Kirk Winges of McCulley Frick & Gilman. The model CALPUFF was used with wind field inputs from the model CALMET to generate estimates of hourly and annual pollutant concentrations within 150 miles of the plant in an area stretching roughly from Bellingham, Washington to Salem, Oregon (Ref. 40, p. 5-7). The results from this modeling indicate the following:

a. Peak 24-hour NO_x concentrations of 12 to 14 $\mu g/m^3$ (0.007 ppm) are predicted east-southeast of the plant for forecasted emissions in the year 2000 with NO_x emission reductions in effect at the plant. This level is about 14% lower than the modeled peak concentration without NO_x emission controls (Ref. 40, App. C).
b. Maximum annual average NO_x concentrations of 1.0 to 1.2 $\mu g/m^3$ (< 0.0006 ppm) are predicted north-northeast of the plant for the year 2000 emissions with NO_x emission controls in operation at the plant. This predicted concentration is approximately the same magnitude as the estimate without a 30% NO_x emission reduction (Ref. 40, App. C).
c. The modeled NO_x concentrations are all substantially below the applicable State and National Ambient Air Quality Standards of 100 $\mu g/m^3$.

4.4.2 Human Health Effects

In the Samet et al. 1997 study entitled "An Assessment of the Health Risks Due to Air Emissions from the Centralia Power Plant", emissions from the Centralia Plant were modeled to generate hourly and annual pollutant concentrations for a grid of points in a region within 150 miles of the plant stretching roughly from Bellingham, Washington to Salem, Oregon. The health effects assessed in this study arise from exposures to particles, including acidic particles, and NO_x both before and after installation of emission controls. Some of the NO_x converts to nitrate (NO_3), a fine aerosol assumed to all be less than 2.5 μm in diameter that will primarily be in the form of ammonium nitrate (Ref. 40, p. 6-7).

Modeled pollutant concentration increments were combined with population data to produce increments in exposure. The population exposure increments were combined with risk coefficients describing the mortality or morbidity associated with the pollutants to characterize the risk from plant emissions. The risk estimates for mortality and morbidity associated with the Centralia Plant should not be construed as actual mortality and morbidity, but may be used for comparing to estimated risks from other air pollution sources (Ref. 40, p. 63). The effect on health impacts resulting from NO_x emission reduction cannot be easily isolated. Quantified results are provided for fine particulate matter, which includes nitrates as well as other aerosols. Estimated concentrations of nitrate aerosol as well as gaseous NO_x do not appear to present a short-term health risk. The effect of aerosols is summarized in TSD '5.4.2 Particulate Matter, Health Effects.

4.4.3 Visibility Improvement

Based on estimated visibility degradation in Mount Rainier National Park originating from present NO_x emissions at the Centralia Plant, the improvement in visibility from NO_x reductions of 15% to 50% is expected to be small. Present NO_x emissions contribute about 1% or less to non-Rayleigh scattering at Mount Rainier, so the available margin for improvement is likewise small. Visibility improvements may be difficult to observe because of growth in the Seattle-Tacoma urban area offsetting the gains shortly after they are achieved, but this does not mean such efforts are not warranted. Reductions in NO_x emissions at the Centralia Plant can alleviate further degradation of visibility in nearby Class I areas.

4.4.4 Odor and Other Nuisance Issues

Odor is not an issue for any of the low-NO_x burner technology alternatives, boiler tuning, fuel and air tips, or natural gas reburn. SCR and SNCR alternatives that use ammonia as a reagent may cause odor in the fly ash, rendering it unusable as a building or construction material. The degree of ammonia slip and reaction of ammonia with NO_x in the control device will determine the extent of any odor issue. Air emissions from SCR or SNCR systems are not expected to cause odor nuisances in the ambient air.

4.4.5 Acid Deposition

There is strong basis for concern that the long-term integrity of lakes in the Cascades could be affected if atmospheric deposition contains pollutants. It is generally accepted that surface waters with chemical characteristics like those in the Cascades are indicative of extremely sensitive systems, but as yet these lakes do not exhibit any signs of acidification from atmospheric deposition (Ref. 13, pp. 19 and 24; Ref. 15, pp. 58 and 84; and Ref. 16, p. 35). Reduction in nitrate loading resulting from reductions in NO_x emissions will provide relief for these sensitive aquatic systems. Less nitrogen deposition to land will reduce the likelihood of nitrogen-saturation so less available nitrogen will run off into nearby waters and diminish the effects of acidification of both the soils and waters.

Modeling of nitrogen deposition using the CALMET/CALPUFF modeling system was conducted by John Vimont of the NPS. Based solely on a controlled NO_x emission rate of 12,000 tons/yr from the Centralia Plant (low NO_x burners with CCOFA and SOFA) without the effect of any other sources, the model predicted a peak nitrogen deposition rate in Mount Rainier National Park of 0.035 kg/ha/yr at the northwest corner of the Park. For a controlled NO_x emission rate of 5,600 tons/yr from the Centralia Plant (post-combustion SCR system) and no other sources, the model predicted a peak nitrogen deposition rate in Mount Rainier National Park of 0.017 kg/ha/yr at the northwest corner of the Park. These same levels of nitrogen deposition were also predicted to occur in the Clearwater Wilderness, site of acid-sensitive lakes. The maximum nitrogen deposition rate due to Centralia Plant NO_x emissions occurs nearby the Plant and is estimated at about 0.08 to 0.09

kg/ha/yr for the 12,000 tons/yr scenario and approximately 0.05 kg/ha/yr for the 5,600 tons NO_x/yr scenario (Ref. 45).

For protection of sensitive lakes and streams in Mount Rainier National Park and North Cascades National Park, an interim nitrate deposition guideline of 5 kilograms of nitrate as nitrogen per hectare per year (kg N/ha/yr) is recommended. This recommendation for maximum nitrogen loading to these two parks is predicated on the following:

a. The recommended nitrogen loading may not protect aquatic resources from episodic acidification from nitrogen deposition. Episodic acidification will precede chronic acidification in many systems, particularly in view of the importance of snow to the hydrologic budgets of the alpine lakes.
b. The recommended nitrogen loading may not address possible influence of low levels of nitrogen deposition on species composition of plant communities (Ref. 4, p. ix).

4.4.6 Ozone in Urban Areas

Reductions in NO_x concentrations due to emissions from the Centralia Plant were predicted as part of the Samet et al. health effects study using the three-dimensional complex dispersion model CALMET. Hourly and annual average NO_x concentrations were determined for an area stretching roughly from Bellingham, Washington to Salem, Oregon. In the Portland-Vancouver metropolitan area, the Centralia Plant=s contribution to the annual average NO_x concentration was less than 0.2 $\mu g/m^3$ (0.0001 ppm), while the maximum 24-hour concentration was estimated to be about 2 $\mu g/m^3$ (0.0011 ppm) following installation of NO_x controls at the plant. For the Seattle-Tacoma urban area, the plant=s contribution to the annual average NO_x concentration was about 0.2 to 0.5 $\mu g/m^3$ (< 0.0003 ppm), while the peak 24-hour concentration was estimated to range from 2 to 4 $\mu g/m^3$ (0.001 to 0.002 ppm) once NO_x emission controls are operational at the plant (Ref. 40, App. B).

4.5 Capital and Operating Costs of the Additional NO_x Controls

4.5.1 Elements of Total Capital Costs

Stone & Webster developed costs for the NO_x control technology options from various sources. Cost estimates for fuel and air tip replacement are based on material estimates provided by ABB-Combustion Engineering for other PacifiCorp coal-fired units. Low NO_x combustion system costs were developed from budget estimates provided by equipment vendors specific to Centralia Units #1 and #2, and from in-house Stone & Webster data for units similar to the Centralia Plant. Capital costs for natural gas reburn, SNCR, and Hybrid technologies are based on correspondence with a technology supplier specific to Centralia Units 1 and 2. The capital costs of natural gas reburn are based on the second generation system design which does not include a costly flue gas recirculation system. SCR capital costs were estimated by Stone & Webster from EPA-published algorithms assuming a moderate level of retrofit difficulty. A Centralia Plant heat rate was then substituted in the flow rate parameter to obtain a more plant-specific value which is more comparable to the other technology cost estimates which consider plant parameters. The adjusted per unit capital costs developed by Stone & Webster for the RACT submittal are summarized below (Ref. 29, Appendix E, p. 4-7).

Emission Reduction Technology	Capital Costs (1,000$)	Capital Costs ($/kW)
Boiler Tuning	536	0.40
Fuel and Air Tip	4,556	3.40
LNB with CCOFA	6,030	4.50
LNB with SOFA	11,390	8.50
Selective Noncatalytic Reduction (SNCR)	9,648	7.20
LNB with CCOFA plus SOFA	14,070	10.50
Hybrid (SNCR plus air heater SCR)	20,904	15.60
Natural Gas Reburn	20,100	15.00
Selective Catalytic Reduction (SCR)	94,633	70.60

4.5.2 Elements of Annual Operating Costs

Operating & Maintenance (O&M) costs were developed by Stone & Webster for each of the candidate technologies. Fixed O&M costs for combustion process modifications were assumed to be negligible compared to present operating conditions. Fixed O&M for Hybrid and SCR systems include one full-time operator per unit plus 1% of direct capital costs for annual maintenance. SNCR fixed O&M costs relative to present operations include one full-time operator and 1.5% of direct capital costs for annual maintenance. Variable O&M costs above current operations for CCOFA, SOFA, and the two modifications combined are based on effects of unburned carbon on boiler efficiency. Ash sales were not assumed to be adversely impacted by combustion modifications. Variable O&M costs for natural gas reburn are based on the added cost of natural gas, estimated as a 1996 to 2015 levelized cost to be $2.00/MBtu, displacing 15% of the heat input otherwise provided by coal consistent with reported performance of 2nd Generation Gas Reburn technology (Ref. 46). EPA cost algorithms were used to develop variable O&M costs for SCR, and were partially used for SNCR and Hybrid systems. The Centralia Plant heat rate was substituted in the flow rate parameter in the SCR cost algorithm to obtain an estimate comparable to the other technology cost estimates which consider plant parameters. Variable O&M costs for SNCR and Hybrid technologies were also based on budget estimates from equipment vendors. Lost ash sales were included separately as part of the variable O&M relative to present operation for the options that would use ammonia and/or urea as reagent. The fixed and variable O&M costs relative to present operations are summarized below (Ref. 29, p. 95; App. E, p. 4-7).

Emission Reduction Technology	Fixed O&M ($ per yr)	Variable O&M ($ per yr)
Boiler Tuning	$0	$0
Fuel and Air Tip	$0	$0
LNB with CCOFA	$0	$216,926
LNB with SOFA	$0	$216,926
Selective Noncatalytic Reduction (SNCR)	$336,072	$10,629,356
LNB with CCOFA plus SOFA	$0	$216,926
Hybrid (SNCR plus air heater SCR), ash sales	$406,824	$10,195,505
Hybrid, with penalty for no ash sales	$406,824	$12,690,149
Natural Gas Reburn	$0	$13,991,703
Selective Catalytic Reduction (SCR), ash sales	$883,093	$14,295,896
SCR, with penalty for no ash sales	$883,093	$16,790,540

4.5.3 Cost Discussion

In evaluating the economic feasibility of RACT for Centralia Plant, SWAPCA gives significant weight to the efficiency and fairness measure of cost effectiveness, or dollars expended per ton of pollutant reduced. The total annualized cost ($/yr) is divided by the emission reduction (tons/yr) achieved by the relevant emission control technology to obtain a ratio in dollars/ton. This cost effectiveness value is used to compare alternative control technologies under consideration for the Centralia Plant and to compare the plant with other similar sources.

A comparison of the NO_x control technologies was presented in the RACT submittal in which all options were assessed on the basis of cost effectiveness. Respondent's cost effectiveness numbers are based on emission reductions from present levels of emissions. However, note that present levels of NO_x emissions are not enforceable at the present time since the Title IV "Early Election" level of 0.45 lb/MBtu, annual average, is an incentive level that, if met starting in 1997, defers compliance with the Phase II rate of 0.40 lb/MBtu from the beginning of 2000 until 2008. A more appropriate expression of cost effectiveness is a range of dollars per ton reduced based on the NO_x emission reduction compared to both baseline emissions and the maximum emissions at 70% CF, which were presented in '4.3.1 above. Maximum emission at 70% CF is calculated from the highest recorded concentration of NO_x, 0.61 lb/MBtu, measured during stack tests in the last eight years.

The annualized cost expresses the capital and levelized O&M costs for each technology as an effective annual sum over the 30 year life of the project. Capital costs, although incurred at the beginning of the project, are converted to an annualized basis which depends on the discount rate of the Plant owners. An owner-weighted discount rate of 9.13% is used to evaluate all candidate technologies (Ref. 29, p. 95). The cost effectiveness of the NO_x reduction technologies based on a 70% capacity factor are presented below:

	Annualized	Cost Effectiveness ($/ton)		
Emission Reduction Technology	Cost ($/year)		vs. Max	vs. Baseline
Boiler Tuning	$52,775		$6	$61
Fuel and Air Tip Replacement	$448,584		$55	$521
LNB with Close Coupled Overfire Air (CCOFA)	$810,639	$90	$471	
LNB with Separated Overfire Air (SOFA)	$1,338,385	$107	$259	
Selective Noncatalytic Reduction (SNCR)	$11,915,370		$923	$2,131
LNB with CCOFA plus SOFA	$1,602,258		$113	$233
Hybrid (SNCR plus air heater SCR), ash sales	$12,660,537		$841	$1,635
Hybrid, with penalty for no ash sales	$15,155,181		$1,007	$1,957
Gas Reburning	$15,970,757		$1,031	$1,954
Selective Catalytic Reduction (SCR), ash sales	$24,496,561		$1,186	$1,837
SCR, with penalty for no ash sales	$26,991,205		$1,307	$2,024

Cost effectiveness of NO_x reductions based on emission reductions as presented in '4.3.1.

The cost effectiveness comparison shown above changes only slightly at higher or lower capacity factor than the assumed 70%. At higher capacity factor, e.g., 85%, all cost effectiveness values decline because the fixed O&M and capital costs are spread across a larger total of emission reduction which each technology provides when operating closer to capacity. Similarly, the cost effectiveness of all technologies decreases at a lower capacity because fixed costs are a larger component of total annualized cost. The relative change is greater for those options with lower

NO_x removal efficiencies. The relative ranking of technology options is unaffected by analysis at different capacity factors. SNCR is more sensitive to capacity factor than SCR due to its higher reagent consumption, but not enough to change the relative comparison. Emission control efficiency may decrease slightly for SCR at higher loads because of enhanced ammonia slip.

The cost effectiveness values for the NO_x emission reduction technologies may best be understood when plotted against the emission reduction achieved as in Figure 4-2 below. The scale shown for cost effectiveness is based on emission reductions compared to baseline; if the PTE cost effectiveness values were used the relative comparisons among options would not change, only the numerical scale for cost effectiveness would be different.

The NESCAUM Stationary Source Review Committee recommended a limit of 0.38 lb NO_x/MBtu, 24-hour average, for tangential coal-fired boilers in its Phase I of emission reductions. The Committee considers this limit to be among those achievable without the use of post-combustion add-on control equipment, such as SCR or SNCR. The vast majority of utility boilers in the Northeast can comply with these Phase I limits at a cost of less than $1000 per ton of NO_x removed, and a few boilers may incur a cost of up to $2000 per ton. Even if actual costs are double the range given, the NESCAUM Committee believes that such costs would be considered economically cost effective as RACT in the ozone nonattainment area (Ref. 53). In the attainment or non-classified areas of the Pacific Northwest, the cost benchmarks would of course not be as high as those given for the NESCAUM region, one of the most problematic ozone nonattainment areas in the nation. However, the cost effectiveness values cited by the NESCAUM Committee do provide a reference point in evaluating RACT costs in an attainment or non-classified area.

Figure 4-2

The cost effectiveness of NO_x reduction technology at coal fired power plants elsewhere in the nation which have been required to meet Federal or state RACT in the last five years are presented below for comparison with the control technology options available to the Centralia Plant. Cost data are not available for all units listed by this reference. The following pulverized coal, dry bottom plants located in Pennsylvania which burn Eastern bituminous coal are ranked by increasing cost effectiveness of the control technology, low NO_x burners with SOFA Level III, installed to meet state RACT requirements (Ref. 47). The indicated percent reductions pertain to the 30-day limit; actual operating data and corresponding emission reductions have been presented in '4.3.1 above.

Unit Identification	Capacity (MW)(lb/MBtu)	30-day Limit Reduction	Percent ($/ton reduced)	Cost Effectiveness Year	Dollar
Penn P&L Brunner Island #3	745	0.45	47.0%	$188	1993
GPU Genco Keystone #2	893	0.45	38.0%	$293	1994
GPU Genco Conemaugh #2	893	0.45	37.0%	$305	1991
GPU Genco Keystone #1	893	0.45	35.0%	$350	1994
GPU Genco Conemaugh #1	893	0.45	33.0%	$360	1991
Penn P&L Brunner Island #2	390	0.45	40.0%	$428	1994
Penn P&L Brunner Island #1	334	0.45	30.0%	$681	1994
Met. Ed. Portland #2	243	0.43	34.9%	$1,222	1993
Met. Ed. Portland #1	158	0.37	37.3%	$1,298	1993

The cost effectiveness of low NO_x burners with CCOFA and SOFA for the Centralia Plant ranges in 1997 dollars from $113 to $233 per ton of NO_x emissions reduced. LNB systems with CCOFA and SOFA are demonstrated to be available at a reasonable cost. This system can be procured and installed at a capital cost of about $14 million, which is similar to the $10 million capital cost estimate projected by PacifiCorp during the CDM process.

4.6 NO_x RACT Determination and Conclusions

Air pollution controls for NO_x can reduce emissions from 5% to 70% depending on the level of emission reduction necessary to comply with this RACT determination. Although RACT is based on reasonably available technologies as defined in RCW '70.94.154, the determination takes the form of an emission limit, rather than a technology prescription. When setting an emission limit, SWAPCA will consider the expected performance of the technology type on which RACT is based. Selection of a NO_x control system that meets RACT is not expected to result in violations of the new RACT emission limit.

An emission limit of 0.30 lb/MBtu based on a plant-wide annual average, i.e. both units averaged together, has been determined to be RACT for NO_x emissions based on consideration of each of the preceding sections and the following:

The technology of low NO_x burners with CCOFA plus SOFA has been identified by burner vendors to be able to meet an annual average of 0.26 to 0.30 lb/MBtu for the Centralia Plant.

Presumptive RACT is defined by PaDEP for coal-fired combustion units with input heat rate greater than 100 million Btu/hr to be the installation and operation of low NO_x burners with separate overfire air. This technology, when applied to large tangentially-fired units, is considered capable of achieving 0.26 to 0.30 lb/MBtu, annual average, for the Centralia Plant based on vendor performance quotations.

The Labadie Plant Unit 4, a 620 MW tangentially-fired unit burning a blend of bituminous and subbituminous coal, has achieved an annual average of 0.22 lb/MBtu in 1996, and a six-month average of 0.21 lb/MBtu in the first half of 1997.

A comparison of the improvement associated with low-NO_x Level III over low-NO_x Level II, and use of 1995-96 Centralia Plant data results in an EPA recommended NO_x emission limit range of 0.23 to 0.37 lb/MBtu. With the current NO_x emission rate performance at Centralia Plant equated to low-NO_x Level I, the performance of the retrofit units in EPA's database indicates an achievable emission rate limit of 0.30 lb/MBtu, which is midway in the range suggested by the EPA Acid Rain Division.

The emission level selected is at the higher end of the range of emission rate performance as stated in a plant-specific evaluation of this technology. Low load operation may result in somewhat higher emission rates, but operator intervention has shown the ability to minimize NO_x rates at low loads and low NO_x burner technology is expected to provide similar capabilities. An annual averaging period allows for greater short-term variability and will allow a lower average limit to be achievable when compared to the typical monthly and daily average levels set elsewhere in the nation.

The effect of NO_x emissions from the Centralia Plant on ozone maintenance areas in the Pacific Northwest has been minimal to insignificant and the 30% or greater reduction in NO_x emissions will reduce any potential further impact. Peak 24-hour NO_x concentrations of about 0.007 ppm are predicted east-southeast of the plant for forecasted emissions in the year 2000 that include a 30% NO_x emission reduction over uncontrolled levels. Estimated concentrations of nitrate aerosol as well as gaseous NO_x do not appear to present a short-term health risk. The total annual load of fixed nitrogen in the environment resulting from plant NO_x emissions and subsequent chemical reactions in the atmosphere, which transform the NO_x to NO_3, is considered to be the most significant impact which should be minimized by a RACT emission limit. Therefore, no short term RACT emission limit will be established since the protection afforded by a 0.30 lb/MBtu annual average emission limit will address the most significant emission impacts.

The cost effectiveness of low NO_x burners with CCOFA and SOFA (Level III) ranges from $113 to $233 per ton of NO_x emissions reduced based on plant-specific quotations. As shown in Figure 4-2, the Level III option is projected to achieve a considerable reduction of NO_x emissions without an enormous jump in cost effectiveness as is the case for options that provide further NO_x emission reductions. This system can be procured and installed at a capital cost of about $14 million, which is similar to the $10 million capital cost estimate projected by the Centralia Plant during the CDM process.

The cost effectiveness of coal fired power plants elsewhere in the nation which have been required to meet Federal or state RACT in the last five years range from $188 to $681 per ton of emissions reduced for pulverized coal, dry bottom plants located in Pennsylvania. The plants for which this data are summarized are of similar configuration as Centralia Plant and range in size from 334 to 893 MW, or 3345 to 8010 MBtu/hr heat input rate compared to each Centralia Plant unit's heat rate of 7015 MBtu/hr.

The establishment of a RACT emission limit must consider technological and economic feasibility. Reasonableness implies that similar sources bear similar costs for emission reductions. Cost effectiveness measured in dollars per ton of emission reduced is a very important factor in selection of an emissions control level consistent with the principles of RACT.

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Section 5

PM RACT EVALUATION

5.1 Impact of PM Emissions on Air Quality

5.1.1 Facility Emissions

Particulate matter emissions from the Centralia Plant boilers consist of nearly all fine particulate classified as PM_{10}. The plant has emitted the following quantities of particulate matter over the last four complete operating years (Ref. 29, App. F):

Year:	1993	1994	1995	1996
Emissions (tons/yr):	2,944	3,240	2,177	3,428

Historical emission concentrations (most recent 8 years) have been measured periodically by stack test and have averaged 0.0154 gr/dscf typically using PSAPCA Method 5 (see Appendix D of this document). PSAPCA Method 5 includes the front half as measured by EPA Method 5 and the back half condensibles. Front half only (EPA Method 5) emissions over this same period have averaged 0.002 gr/dscf for Unit 1 and 0.005 gr/dscf for Unit 2. The highest recorded front half value for Unit 1 is 0.005 gr/dscf and the highest front half value for Unit 2 is 0.0243 gr/dscf. The Unit 2 value is substantially higher than other previously recorded values. This value is within current permitted values but is anomalous as the data set of front half test results below demonstrates (Ref. 29, p. 127).

Particulate Matter Emission Tests (Front Half)

Year of Test	Unit #1 (gr/dscf)	Unit #2 (gr/dscf)
1990	0.0011	0.0061
1991	0.0021	0.0012
1992	0.0021	0.0020
1993	0.0022	0.0059
1994	0.0013	0.0010
1995	0.0014	0.0048
1996	0.0010	0.0243
1997	0.0051	-----

The current configuration for control of particulate matter at the Centralia Plant is two electrostatic precipitators (ESPs) in series. This combination of controls provides 99%+ control efficiency for particulate matter. The particulate matter consists of fly ash released from coal during combustion and condensible particles that will condense and be collected in the ESPs as the emission gases cool. All particulate matter released to ambient air for purposes of this evaluation is considered to be PM_{10}. This is reasonable because of the unique control strategy employed at the plant. In addition, sulfate and nitrate aerosols are considered to be particulate matter, but would not be effectively controlled by traditional particulate matter collection devices because they are emitted in gaseous forms (SO_2 and NO_2) and through complex atmospheric chemical reactions become secondary particulate matter. It is these aerosols that would contribute most significantly to visibility impairment, acid deposition, and potential health impacts.

5.1.2 Ambient Levels of PM_{10} and $PM_{2.5}$

Before 1987, the National Ambient Air Quality Standards (NAAQS) for Total Suspended Particulate (TSP - #100 µm) were 75 µg/m^3 geometric mean primary, and 60 µg/m^3 geometric mean secondary, and 260 µg/m^3 24-hour primary and 150 µg/m^3 24-hour secondary standard based on the second highest value. In 1987, the EPA established NAAQS for particulate matter having an aerodynamic diameter of 10 microns (µm) or less, referred to as PM_{10}. The NAAQS consist of an annual arithmetic mean not to exceed 50 µg/m^3, and a 24-hour standard of 150 µg/m^3, not to be exceeded more than once per year. The Washington State ambient air quality standards for PM_{10} are identical to the federal standard. New ambient standards for $PM_{2.5}$ (particulate matter less than 2.5 µm in diameter) were finalized by EPA on July 18, 1997 and will be implemented during a long transition period set to begin September 16, 1997. The new standards are 15 µg/m^3, annual average, and 65 µg/m^3 averaged over a 24-hour period with compliance based on the highest 2% of monitored values in a calendar year.

5.1.2.1 Total PM_{10}

Ash, a naturally-occurring constituent of coal, is released upon combustion and becomes either bottom ash which falls out into the bottom of the boiler, or fly ash which is conveyed by the flue gases to the two electrostatic precipitators (ESPs) in series which collect approximately 99.6% of the total particulate matter. The fly ash at Centralia Plant comprises 59% to 69% of the total ash present in the coal. Each unit is equipped with a Koppers weighted-wire ESP with a specific collection area (SCA) of 383 ft^2/1,000 cfm, followed by a Lodge-Cottrell rigid-frame ESP that has a SCA of 384 ft^2/1,000 cfm.

No PM_{10} monitors are currently operating in the vicinity of the Centralia Plant. The closest monitor is located in Lacey at the Mountain View Elementary School. The PM_{10} ambient air quality standards of 150 µg/m^3, 24-hour average and 50 µg/m^3, annual average have not been exceeded in western Washington since 1990 (Ref. 29, p. 146).

The Olympia-Lacey-Tumwater area was designated by EPA as a PM_{10} nonattainment area in 1987. An aerosol characterization study in 1986 determined that residential wood combustion was the largest contributor (up to 90%) of fine particulate matter during inversions. A PM_{10} saturation study conducted in the winters of 1994-95 and 1995-96 by the Olympic Air Pollution Control Authority indicated that the Mountain View monitoring site in Lacey is adequate for measuring representative and maximum PM_{10} concentrations within the nonattainment area. No exceedences of the PM_{10} standard have occurred at the Lacey site since 1988. The Olympia-Lacey-Tumwater area is awaiting final approval by EPA of redesignation which is expected in early 1998 (Ref. 55, p. 2 and 9).

The largest sources of $PM_{10/2.5}$ in the western Washington emission inventory are re-entrained road dust from automobiles and agricultural dust. All point sources comprise a small fraction of the overall inventory, although this portion is larger for $PM_{2.5}$ particles (Ref. 30, p. 13).

Fine particulate matter in the Puget Sound area has been linked to wood combustion based on a 1993 source apportionment study conducted by Yuen and Larson of the University of Washington. Weekly composite samples of $PM_{2.5}$ were collected at three residential sites from January 1991 through January 1992 and analyzed for a set of elements used to assess the contributions from different chemically distinct sources. The findings of this study were the following (Ref. 56, p. 12 and 22):

a. Wood smoke particles are the largest contributor to annual average $PM_{2.5}$, heating season $PM_{2.5}$, and non-heating season $PM_{2.5}$.

b. During the heating season, the average $PM_{2.5}$ concentration is two to three times higher than during the other seasons and most of the increased $PM_{2.5}$ mass is from residential wood combustion.

c. Airborne sulfate contributes a significant fraction of the $PM_{2.5}$ mass during the summer. The source of the atmospheric sulfate could not be identified with confidence.

d. The annual average $PM_{2.5}$ concentration during the analysis period ranged from 15.7 to 16.6 $\mu g/m^3$ for the Lake Forest Park, Marysville, and Puyallup sites. Based on a chemical mass balance receptor model, the annual average $PM_{2.5}$ concentration due to wood combustion for the same period was 11 to 12 $\mu g/m^3$ at the three monitoring sites, or about 70% of the total measured fine particle mass.

Modeled increments to ambient concentrations due to the Centralia Plant were predicted in the 1997 study "An Assessment of the Health Risks Due to Air Emissions from the Centralia Power Plant" by Jonathan Samet et al. of the Johns Hopkins University Department of Epidemiology and Kirk Winges of McCulley Frick & Gilman. In this work, the Centralia Plant was the only source from which emissions were modeled. Hourly concentrations of particulate matter, which includes primary particles (PM_{10}) plus secondary sulfate and nitrate aerosols ($PM_{2.5}$), were modeled for an area within 150 miles of the plant stretching roughly from Bellingham, Washington to Salem, Oregon. The results from this modeling indicate the following (Ref. 40, App. C):

a. A peak 24-hour PM concentration of 3 to 4 $\mu g/m^3$ south-southwest of the plant was predicted to have occurred based on 1990 data. Peak values of 4 $\mu g/m^3$ in a similar location are predicted for the year 2000 with no SO_2 and NO_x emission controls on the plant. The modeled result assumes an increase in emissions due to increased plant utilization and higher coal sulfur content compared to 1990 (Ref. 29, p. 51-52 and Appendix L, p. 46-47).

b. Maximum annual average PM concentrations of 0.16 to 0.18 $\mu g/m^3$ south-southwest of the plant are predicted to have occurred based on 1990 data. Annual average concentrations of 0.20 to 0.22 $\mu g/m^3$ are predicted in a similar location for the year 2000 with no SO_2 and NO_x emission controls on the plant. The modeled result also assumes an increase in emissions due to increased plant utilization compared to 1990 (Ref. 29, p. 145; Ref. 40, p. 46-47).

5.1.2.2 Contribution of Sulfates and Nitrates to Secondary Aerosols

Sulfates and nitrates are secondary aerosols formed from conversion of SO_2 and NO_x, respectively, in the atmosphere by a series of chemical reactions that depend upon weather conditions, particularly relative humidity. Both sulfate (SO_4) and nitrate (NO_3) aerosols are considered to be $PM_{2.5}$ (particles of diameter less than 2.5 μm), and are also components of PM_{10} (particles of diameter less than 10 μm). Measurement of ambient SO_4 and NO_3 is not routinely conducted as a part of the state-wide pollutant monitoring network.

In their 1993 study, Yuen and Larson identified by elemental analysis the sulfur portion of total $PM_{2.5}$ as about 4.5%, the largest share of any single trace element. Based on the measured elemental concentrations, the authors predicted by source apportionment techniques the $PM_{2.5}$ mass attributed to atmospheric sulfate. An annual average of 1.9 to 2.9 $\mu g/m^3$ of sulfate, or 15 to 21% of $PM_{2.5}$ mass, was predicted at the three monitoring sites. The source of the atmospheric sulfate could not be identified with confidence (Ref. 56, pp. 11-15).

Samet et al. and Winges modeled increments to ambient concentrations of sulfate and nitrate due to the Centralia Plant, which was the only source modeled in their analysis. Hourly concentrations of secondary sulfate and nitrate aerosols ($PM_{2.5}$), were modeled for an area within 150 miles of the plant. The results from this modeling indicate the following (Ref. 40, Appendix C):

a. Peak 24-hour SO_4 concentrations of 1.6 to 2.0 $\mu g/m^3$ north-northeast and NO_3 concentrations of 0.8 to 1.0 $\mu g/m^3$ south-southwest of the plant are predicted for 1990 and forecast year 2000 emissions with no SO_2 or NO_x emission controls on the plant.

b. Maximum annual average SO_4 concentrations of 0.08 to 0.11 $\mu g/m^3$ northeast and south of the plant, and NO_3 concentrations of 0.04 to 0.05 $\mu g/m^3$ south of the plant are predicted for 1990 and forecast year 2000 emissions with no SO_2 or NO_x emission controls on the plant.

c. The population-weighted annual average particulate matter concentration, both primary and secondary aerosols, over the entire modeling domain is predicted to be 0.12 $\mu g/m^3$ for projected 2000 population levels and no SO_2 or NO_x emission controls at the plant (Ref. 40, p. 48 and Table 6).

d. The predicted ambient concentrations are a small percentage of the new NAAQS for $PM_{2.5}$ of 15 $\mu g/m^3$ annual average and 65 $\mu g/m^3$ 24-hour average (Ref. 29, p. 153).

Using the total cumulative exposure approach in the BPA report, Samet et al. estimated the impact of total particulate matter emissions from the Centralia Plant by itself without additional emission controls according to the Glantz et al. model to be 7 cases of bronchitis per year (Ref. 40, p. 24 & Table 4). Samet et al. state that limitations are evident in the approach used by Glantz et al. noting that its air pollution model fails to account for terrain or chemical reactions that produce secondary aerosols, and its health risk calculations use risk coefficients from older epidemiologic studies.

5.1.3 Human Health Effects of PM_{10} and $PM_{2.5}$

Recent studies have shown statistically significant, positive associations between measures of particle concentration, primarily TSP and PM_{10}, and daily mortality counts for some regions in the U.S. Similar positive reports have been published based on data from cities throughout the world. However, the toxicologic mechanisms by which inhaled particulate matter at current levels in the U.S. could lead to cardiopulmonary morbidity and mortality are yet to be established and this gap limits the interpretation of these data for use in predicting health effects (Ref. 40, p. 15-16).

In the 1997 study entitled "An Assessment of the Health Risks Due to Air Emissions from the Centralia Power Plant", Samet et al. assess the risk in western Washington and northwest Oregon from increments to pollutant concentrations due to the Centralia Plant. Exposure to particulate matter includes both primary combustion emissions and secondary particulate matter from formation of sulfate (SO_4) and nitrate (NO_3). The secondary aerosols are assumed to all be $PM_{2.5}$ and typically are combined with ammonium in the atmosphere. The risk assessment identified sulfates as the largest component of total particulate concentrations, with secondary nitrates and primary particles emitted directly from the plant as smaller components.

Modeled pollutant concentration increments were combined with population data to produce increments in exposure. The population exposure increments were combined with risk coefficients describing the mortality or morbidity associated with the pollutants to characterize the risk from plant emissions. The risk estimates for mortality and morbidity associated with the Centralia Plant should not be construed as actual mortality and morbidity, but may be used for comparing to estimated risks from other air pollution sources (Ref. 40, p. 58). Health impacts were summarized as follows:

a.The risk of premature mortality from all plant aerosol pollutants is estimated throughout the study area to be 3.3 to 34.6 with no scrubbers depending on the assumptions selected for estimating risk. For King County alone, the study projected using the same methodology and 1990 data a risk of premature mortality due to all ambient air pollution of 2,053 annually (Ref. 40, p. 7 and 64).

b.Using the same mortality calculation approach, the study authors calculated premature mortality from wood smoke and mobile sources in Seattle. Based on the Yuen and Larson result that approximately 71% of $PM_{2.5}$ in the Seattle area is attributable to wood smoke, a premature mortality of 1,455 would be attributed to wood smoke and 328 would be attributable to mobile sources in Seattle (Ref. 40, p. 65).

c.Using rates provided by the National Center for Health Statistics, the study estimated the numbers of emergency room visits and outpatient visits for asthma by county for the year 1990. Visits attributable to Centralia Plant operations represent a very small proportion of the total (Ref. 40, p. 64).

d.Emergency room and outpatient facility visits estimated to result from plant emissions range from 70 to 106 with no SO_2 controls in place. This compares with an estimated total of 260,000 asthma-related visits each year in the study area (Ref. 40, p. 7 and Table 18).

e.Exposures to air pollution resulting from Centralia Plant emissions for 5.5 million people residing within a 150-mile radius of the plant were estimated with a state-of-the-art pollution model. Compared to the population's total exposure to air pollution, the Centralia Plant is a minor contributor even without SO_2 controls (Ref. 40, p. 65-66).

In a 1996 report "Breathtaking: Premature Mortality due to Particulate Air Pollution in 239 American Cities", the Natural Resources Defense Council (NRDC) estimated that 307 annual cardiopulmonary deaths were attributable to particulate matter air pollution in the Portland Metropolitan Statistical Area (MSA). For the Seattle-Everett MSA, NRDC estimated 501 annual cardiopulmonary death from particulate matter, and for the Tacoma MSA it estimated 195 deaths. None of these Pacific Northwest MSAs were among the top 50 in the country for attributable mortality (Ref. 57).

An evaluation of the relationship between postneonatal infant mortality and particulate matter in the U.S. has been performed. The study recognized that a majority of infant deaths are unlikely to be influenced by air pollution levels because they occur too soon after birth or are due to causes clearly intrinsic to the infant, such as congenital anomalies. Postneonatal death (death of an infant over 27 days of age) is thought to be influenced more by the infant=s external environment than is mortality earlier in infancy. Several studies have suggested that sudden infant death syndrome (SIDS) is associated with exposures to environmental tobacco smoke. A total of almost 4 million infants born between 1989 and 1991 were included in one study which spanned 86 metropolitan statistical areas. After adjustment for confounding factors in this analysis, infants with high levels of PM_{10} exposure (40.1 to 68.8 $\mu g/m^3$) were at 10% higher risk of postneonatal death than were infants with low exposure (11.9 to 28.0 $\mu g/m^3$) (Ref. 37).

In their 1992 report "Air Quality Analysis and Related Risk Assessment for the Bonneville Power Administration's Resource Program Environmental Impact Statement", Glantz et al. estimated annual cumulative exposures within an 80 km radius based on 1991 emissions data at the Centralia Plant. For population levels projected for the year 2000, the total cumulative exposure was estimated to be 20,759 person-$\mu g/m^3$ due to total suspended particulate matter. However conversion of gaseous SO_2 and NO_x to their aerosol forms sulfate and nitrate, respectively, is not accounted for in the dispersion model so the particulate matter exposure may be underestimated. This study defined half of the particle mass as having a diameter of less than 1 μm (Refs. 40 and 41).

5.1.4 Visibility Impairment

Elemental and organic carbon are contributors to visibility impairment at Class I areas in the Cascade Mountains. The particulate matter directly emitted from the Centralia Plant is referred to as primary particulate, and contains elemental carbon. Because of the high efficiency of the existing ESPs installed at the Centralia Plant, all particulate matter is assumed to be PM_{10}. A portion of the PM_{10} is further defined as $PM_{2.5}$ (fine mass). The mass fraction apportioned to $PM_{2.5}$ was approximately one-half of the ambient PM_{10}, as reported by PREVENT (Ref. 21). Such controls and a review of the SWAPCA files support a conclusion that there are no known or reported instances in which a long-term visible particulate matter plume emanating from the Centralia Plant has caused attributable visibility impacts within a Class I area. Because of the dual ESPs in series and the corresponding fine nature of the particulate matter from the Centralia Plant that is not captured by the ESPs, any contribution to visibility impairment would be expected to be in the form of a homogeneous regional haze. Other emissions at the Centralia Plant, such as SO_2 and NO_x, are emitted in gaseous form and chemically convert to a particulate matter form as a result of complex atmospheric chemical reactions. When measured downstream of the plant by particulate matter or aerosol monitors, these products of atmospheric chemical reactions, such as sulfate and nitrate, are detected as particulate matter. These types of particulates are referred to as secondary particles or secondary aerosol. The primary pollutants for the secondary aerosols sulfate (SO_4) and nitrate (NO_3) would be SO_2 and NO_x, respectively.

As noted in the IMPROVE (Ref. 68) and PREVENT (Ref. 21) reports, visibility issues in the Pacific Northwest are described as regional haze issues. The plain English definition of aerosol is a suspension of colloidal particles in a gas. As described in IMPROVE (Ref. 68, p.1-1) an aerosol is a suspension of fine and coarse solid and liquid particles in air. Particles, especially fine particles less than 2.5 Φm, scatter light and degrade the visual information content of a scene. Fine particles consist of different chemical species either within the same particle (internally mixed) or in different particles (externally mixed). Significant chemical species found in particles include sulfates, nitrates, organics, elemental carbon, and soil dust. The sulfates, nitrates, and some hygroscopic organics absorb water from the atmosphere, thereby increasing significantly the light-scattering particle size and mass. Aerosol (particulate matter) monitoring in the IMPROVE network is accomplished by a combination of particle sampling and sample analysis. Samplers in the IMPROVE network collect four simultaneous samples: one PM_{10} sample on a Teflon filter, and three $PM_{2.5}$ samples on Teflon, nylon and quartz filters. The PM_{10} filter is used to determine total PM10 mass. The $PM_{2.5}$ Teflon filter is used to measure total fine aerosol mass, the nylon filter is used to measure nitrate and sulfate aerosol concentrations, and the quartz filters are analyzed for organic and elemental carbon.

"The largest single component of the fine aerosol in the East is sulfate, while in the Pacific Northwest it is organics, and in southern California it is nitrate. In general, the largest mass fractions of the fine aerosol are sulfate and organics. Of the 21 regions in the IMPROVE network, organic carbon is the largest single component in 10 regions..." (Ref. 68, p. S-4). One of these ten regions is the Cascades which generally defines the area surrounding the Centralia Plant. "Fine aerosols are the most effective in scattered light and are the major contributors to light extinction. In most cases, the sulfate component of the fine aerosol is the largest single contributor to light extinction" (Ref. 68, p. S-9).

As noted in PREVENT, even though sulfate accounted for only 20-30% of the fine mass ($PM_{2.5}$) measured at Tahoma Woods and Marblemount, it was estimated that it made up about 50% of the non-Rayleigh extinction budget. Organic plus light-absorbing carbon contributed about another 15-20%, while nitrates and coarse mass contributed about 10% to the extinction budget. Fine soil was less than 1%. It was expected that the highest concentrations of organics would be found near a forest fire with decreasing concentrations as one moves radially away from the particle source. PM_{10} emissions from the Centralia Plant account for approximately 1% of the total PM_{10} emitted in western Washington and Oregon (Ref. 21).

In the Addendum to PREVENT, conclusions indicated that organics and light absorbing carbon were the single largest contributors to measured fine mass and are the second largest contributor to visibility reduction in Mount Rainier National Park. The empirical regression model attributed most organics and light absorbing carbon to either lead or bromine both of which were shown to be primarily associated with transportation activity. Very little carbon was associated with potassium which was mostly linked to burning. The chemical mass balance (CMB) model suggests that about 50% of the organics at Mount Rainier National Park have an urban transportation origin with fire-related activity accounting for only about 10%. On the other hand, almost 40% of organics are associated with the soil signature suggesting substantial re-entrainment of organic material along with wind blown dust. Light absorbing carbon is also most closely associated with the transportation signature at a greater than 60% contribution. Again only a small fraction (13%) of light absorbing carbon was linked to burning. The soil signature accounted for about 25% of light absorbing carbon.

Conclusions from the PREVENT and IMPROVE reports, which analyzed monitored PM values in and around Mount Rainier National Park and other Class I areas in Washington and considered the actual PM emissions from the Centralia Plant, did not identify a significant impact on visibility due to emissions of primary particulate from the Centralia Plant. The majority of the impacts on visibility were attributed to sulfates, nitrates and organics.

5.1.5 Emission Limit Violations

The opacity limit for the Centralia Plant is established by the Washington state standard of 20%. This limit is applicable during the mode of normal operations and does not include startup and shutdown, or upset conditions. The existing ESPs maintain opacity at approximately 5% during normal operations. Periodically, the ESPs are deenergized as a routine maintenance activity to manually rap the precipitator plates. This manual rapping improves the overall efficiency of the ESPs. If not performed, the efficiency of the ESPs degrades thus allowing opacity to increase from 5% up to as high as 20% where additional maintenance would be required and increases overall PM emissions. Periodic manual rapping of the precipitator plates which results in short term excursions above the 20% limit is the preferred operational mode because it provides for lower overall PM emissions. This maintenance activity is provided for in the regulations. During startup, the ESPs are not on-line due to minimum temperature requirements. Opacity above 20% is experienced during this time but is not a violation of the standard because of regulatory provisions allowing excess emissions under such circumstances. During normal shutdown the temperature of the gases through the ESPs can be maintained until there is no fuel in the boiler and opacity is at a minimum. However, there are a few modes of low power operation where the minimum temperature requirements can not be maintained in the ESPs and they will be off-line. Short term excursions above 20% opacity could be experienced during this time. Again this is allowed as part of the design configuration of the ESPs.

No opacity violations have occurred in recent years. During initial startup of the plant, the Koppers ESPs did not function as designed resulting in numerous exceedences of the opacity limit. To ensure the plant could operate within the 20% opacity limit, a second set of ESPs (Lodge-Cottrell) were added in series in 1974.

In addition to the opacity standard, a Washington State and SWAPCA standard limits particulate matter to 0.1 gr/dscf from any emission unit. Initial permitting of the facility established a limit not to exceed 0.06 gr/dscf (front half only) for the main boilers. This limit applies to only the front-half portion as measured by EPA Method 5 since it is based on a Koppers Company performance guarantee for ESPs, which are not effective at controlling the condensible portion of particulate matter (back half). Except for the problems encountered during initial startup of the plant with the Koppers ESPs, compliance with the 0.10 gr/dscf and 0.06 gr/dscf limits has been achieved since the installation of the second set of ESPs (Lodge-Cottrell). Table IV-2 of the RACT submittal summarizes the results of particulate matter testing at the Centralia Plant (Ref. 29, p. 127). These test results indicate compliance with excess margin. The average concentration for Unit 1 since 1989 is 0.0020 gr/dscf and the average concentration for Unit 2 since 1989 is 0.0058 gr/dscf. The highest recorded values in this time period were 0.0051 gr/dscf on Unit 1 in February of 1997 and 0.0243 gr/dscf on Unit 2 in August of 1996, well below the standard. The highest value was obtained during source testing by a new test contractor using Method 17, and is well above the average values measured by the alternate source test company. These overall low values are attributed to the unique configuration of the plant with the installation of two full capacity ESPs in series. No other coal fired power plant in the United States has this configuration. Collection efficiency for all PM is judged to be above 99.6% based on the source test results (front and back half) and quantity of ash in the coal as determined by ultimate analysis of coal samples.

5.1.6 Odors and Other Nuisance Issues

No complaints have been received by SWAPCA in regards to odors issues from particulate matter emissions from the Centralia Plant.

Over the past several years, there was one health related complaint received by SWAPCA on November 10, 1993. The complainant alleged that high sulfur coal piles were spontaneously combusting releasing sulfur and soot into the air. In addition, this person was aware that soot cleaning was performed at night at the Centralia Plant which releases soot into the air that impacts this person. This person reportedly has gone to hospital on several occasions because of respiratory problems.

There are no other nuisance complaints received by SWAPCA from particulate matter emissions from the Centralia Plant since the early days of initial operation when the ESPs were not functioning properly.

5.1.7 Other Environmental Effects of PM

The fine particulate matter includes acidic species such as sulfate and nitrate which are removed from the atmosphere by dry and wet deposition, the latter occurs usually by rain or snow.

5.2 Availability of Additional PM Controls

Electrostatic precipitators (ESPs) and baghouses are commercially available control technologies for reducing particulate matter from coal-fired boilers. Availability of PM controls is based on a long record of particulate matter control in the electric utility industry. Identification of commercially available control systems starts with recognition of the capabilities of the current ESP system at the Centralia Plant. Some examples from the EPA BACT/RACT/LAER Clearinghouse of PM control systems for similar units and their allowed emission levels are presented below. Improvements to the existing PM control system based on use of available technology are then discussed. Some common technologies considered to be available are identified as being unable to improve PM control relative to the baseline system.

Presently, Centralia Plant PM emissions are 3428 tons/yr. (Ref. 29, Appendix A) Its units are rated at 670 MW and 7,015 MBtu/hr, and the average emission rate from 1993 to the present based on Method 5 source tests which measure filterable and condensible particulate matter is 0.021 lb/MBtu for Unit #1 and 0.034 lb/MBtu for Unit #2.

The Santee Cooper Cross Unit #1, a 500 MW pulverized coal fired plant operated by South Carolina Public Service was permitted in 1994 with an ESP for control of particulate matter to a level of 0.03 lb/MBtu. An Orlando Utilities Commission boiler rated at 4,286 MBtu/hr was permitted in 1991 with an ESP at 0.02 lb/MBtu. In 1991, an Old Dominion Electric Cooperative boiler rated at 4,085 MBtu/hr was permitted with a fabric filter at 0.020 lb/MBtu for total Method 5 PM and a limit of 0.018 lb/MBtu for PM_{10} emissions. Three South Carolina Electric & Gas pulverized coal units, each rated at 385 MW and equipped with fabric filters, were permitted in 1992 with emission limits of 0.020 lb/MBtu for total PM and 0.018 lb/MBtu for PM_{10} (Ref. 47).

The above recent installations on coal-fired boilers indicate ESPs and baghouses to be available control technology for particulate matter. In addition, the performance of existing ESPs may be improved through the use of available operational techniques, such as flue gas conditioning and humidification. Flue gas conditioning lowers the resistivity of the ash particles making them easier to capture. Humidification, which is the injection of a fine mist of water droplets into the flue gas, will lower the gas temperature and increase the gas density, which increases the residence time for the particulate matter within the ESP. Sulfur trioxide injection is a flue gas conditioning technique with promise and is evaluated further. A baghouse PM control option for the Centralia Plant is to replace the internals of the Lodge-Cottrell ESP with a pulse jet baghouse. These options are compared to continued operation of the ESPs with retrofit of an FGD system downstream of the ESP, a configuration expected to decrease PM emissions.

New microprocessor controls on the Lodge-Cottrell ESPs are planned to be installed in 1998 and 1999 to enhance performance and improve reliability. This action is independent of FGD system retrofit.

The following particulate matter control devices cannot achieve the expected PM emission levels provided by the present ESPs supplemented with FGD installation:

Mechanical precipitators (e.g. cyclones)
Side stream cyclones
Wet particulate scrubber

Other particulate matter technologies typically considered available achieve the same level of emission control, or offer only slightly improved performance compared to the ESPs with FGD added in series but at a high cost for the small emission reduction obtained.

5.3 Emission Reduction to be Achieved by Additional PM Controls

5.3.1 Effectiveness of PM Control Options

Installation of FGD systems at other PacifiCorp power plants has resulted in a 20% to 50% reduction in PM emissions, with some systems achieving up to 70% reduction depending on the flue gas particle size distribution. Due to present control efficiency of 99.6% or better, the improvement at Centralia Plant from installation of FGD is expected to be in the lower end of the observed range, or 20% to 30% PM decrease. Fly ash, which exits the boiler with the flue gases and is collected by the ESPs, comprises from 59% to 69% of the total ash present in the coal.

Flue gas conditioning with ammonia or ammonium salts in tandem with sulfur trioxide will form ammonium bisulfate, an agglomerating agent that creates larger particles, in the flue gas. The larger particles are easier to remove from the flue gas in the ESP. Humidification does not increase the effectiveness of ESP units that already perform well. Injection of sulfur trioxide into the flue gas is the most predictable form of conditioning. Sulfur trioxide forms sulfuric acid which condenses on the surface of particles decreasing their resistivity and improving collection. Experience with this conditioning process at other PacifiCorp facilities is quite varied depending on the properties of the coal combusted and the boiler characteristics for conversion of sulfur into other compounds. The most effective means of sulfur trioxide injection is by burning of molten sulfur as used at the

PacifiCorp Naughton Plant. The higher sulfur coal expected to be consumed at Centralia Plant in the future may also increase the level of sulfur trioxide in the flue gas without active injection (Ref. 29, pp. 135-137).

Baghouses are capable of achieving PM control efficiencies of 99.9% or better on utility boilers. An advantage of baghouse filters over ESPs is that ash resistivity does not affect the collection of PM in a baghouse. However, maintenance requirements for baghouses are usually greater than for ESPs due to occasional broken bags or loose seals. The control efficiency of fabric filters installed on coal-fired units 385 MW or larger from 1991 through 1994 is rated as 99.5 to 99.9% (Ref. 47). An FGD system downstream of the existing ESPs makes a baghouse impractical added to the flue gas stream, but a baghouse retrofit to the Lodge-Cottrell ESP housing would achieve the same or slightly higher control efficiency than the existing series ESP.

PM emission projections are based on historical coal quality data, not the projected mine plan. Experience with CMC coal has shown relative consistency in ash fusion temperature which is a good predictor of the split between fly ash and bottom ash. The operating history is considered a good predictor of ash properties, and therefore, the performance of the ESPs as affected by ash characteristics.

Increased concentration of SO_3 due to combustion of higher sulfur coal in the future will only be about 2 to 3 ppm which is not expected to significantly affect ESP collection efficiency beyond only a marginal improvement. This slight increase in boiler exhaust gas SO_3 prior to the FGD scrubbing system compares to SO_3 injection rates of up to 20 ppm at units where active flue gas conditioning is used to improve ESP collection efficiency.

The electrical conductivity of fly ash and the dielectric strength of the bulk ash are two properties important to the electrostatic collection process of ESPs. The higher the dielectric strength of a dust layer on ESP plates, the less sensitive the fly ash is to resistivity effects. Experience shows that coal ashes with resistivities above 5×10^{10} ohm-cm are difficult to collect. Ash resistivity is inversely proportional to the concentration of SO_3 and water in the flue gas and the sodium, potassium, and carbon in the ash. Resistivity is directly proportional to the ash constituents of calcium, magnesium, alumina, and silica. Peak ash resistivities occur between 250EF and 450EF, declining with increasing temperature above about 450EF (Ref. 58, pp. 17.11-17.12). Studies of Centralia Plant fly ash in the mid-1970s indicated the ash resistivity ranges from 5×10^8 to 7×10^{10} ohm-cm depending on sodium content and temperature (range of 665EF to 290EF respectively).

FGD systems typically remove 30% to 50% of the SO_3 entering the absorber vessel. Acid mist plumes become visible when the SO_3 or acid concentration exceeds 15 ppm; at Centralia Plant the SO_3 concentration entering the absorber vessels is expected to not exceed 10 ppm, so no acid plume is envisioned. Total PM emissions from the FGD system, including the condensible fraction, will not increase compared to the total PM which enters FGD absorbers from the ESPs.

5.3.2 Effect of Options on Other Air Pollutants

Installation of the FGD system is for the purpose of reducing SO_2 emissions as described in detail in Section 3. The present ESPs supplemented with FGD may reduce VOC emissions by a small amount due to increased control of condensibles in the FGD as a result of lower flue gas temperature. This effect is described in '3.3.3 since it occurs due to SO_2 control technology. No other stack emissions are changed appreciably due to continued use of the existing ESPs.

Ammonia compounds used for flue gas conditioning may not be completely mixed and result in ammonia slip, or emissions of ammonia to the ambient air.

A pulse jet baghouse in place of the Lodge-Cottrell ESP will have no more than a random, unanticipated effect on the emissions of any other air pollutants from the Plant.

5.3.3 Other Environmental Impacts

5.3.3.1 Water Quality
Particulate matter control technologies capable of the same or slightly higher efficiencies than the dual series ESP system will not create impacts to water quality. Any impact to water quality of wet limestone FGD, which will improve PM emission control about 20%, is discussed in '3.3.3 because the FGD system is designed primarily to reduce SO_2 emissions.

5.3.3.2 Solid and Hazardous Waste
Use of ammonia compounds in flue gas conditioning may render the fly ash unsuitable for sale as an additive in cement. If the fly ash cannot be sold as a product, then it would have to be disposed as a solid waste, resulting in 250,000 to 300,000 tons/yr of material in need of transportation and final disposal. Humidification of the flue gas could result in build up of material inside ducts that would need to be removed causing a negligible increase in solid waste. A baghouse in place of the Lodge-Cottrell ESP would contribute an insignificant increase in solid waste due to replacement of broken or badly worn bags periodically.

5.4 Impact of Additional PM Controls on Air Quality

5.4.1 Ambient PM_{10} and $PM_{2.5}$

5.4.1.1 Total PM_{10}
Increments to ambient concentrations due to the Centralia Plant following installation of SO_2 and NO_x emission controls were predicted by Samet et al. and Winges in 1997. Proposed SO_2 controls will offer marginal improvement in particulate matter control efficiency. The model CALPUFF was used with wind field inputs from the model CALMET to generate estimates of hourly and annual particulate matter concentrations within western Washington and northwest Oregon. The results from this modeling with emission controls in place indicate the following (Ref. 40, p. 5-7):

a. Peak 24-hour PM_{10} concentrations of 1.0 to 1.4 $\mu g/m^3$ are predicted south-southwest and east of the plant for forecasted emissions in the year 2000 with SO_2 and NO_x emission controls in operation. This level represents about a 70 to 75% decrease in modeled peak concentration compared to the case with no added emission controls (Ref. 40, App. C).
b. Maximum annual average PM_{10} concentrations of 0.06 to 0.08 $\mu g/m^3$ are predicted south-southwest and east-northeast of the plant for year 2000 emissions with SO_2 and NO_x emission controls in operation that provide marginal improvement in particulate matter control. This level represents about a 65 to 70% decrease in modeled annual average PM_{10} concentration compared to no emission reductions (Ref. 40, App. C).

c. The modeled PM_{10} concentrations are all substantially below the present PM_{10} NAAQS of 150 $\mu g/m^3$, 24-hour average and 50 $\mu g/m^3$, annual average.

5.4.1.2. Contribution of Sulfates and Nitrates to Secondary Aerosols

In 1997, Samet et al. and Winges modeled increments to ambient concentrations of sulfate and nitrate due to the Centralia Plant, which was the only source modeled in their analysis. Hourly concentrations of secondary sulfate and nitrate aerosols ($PM_{2.5}$), were modeled for an area within 150 miles of the plant. The results from this modeling indicate the following (Ref. 40, App. B):

a. Peak 24-hour SO_4 concentrations of 0.3 $\mu g/m^3$ and NO_3 concentrations of 0.6 to 0.8 $\mu g/m^3$ both south-southwest of the plant are predicted with SO_2 and NO_x emission controls applied to projected emissions for the year 2000. The resulting ambient levels represent about a 70% decrease in modeled daily peak concentration of secondary $PM_{2.5}$ compared with no additional emission controls (Ref. 40, App. C).
b. Maximum annual average SO_4 concentrations of 0.01 to 0.02 $\mu g/m^3$ northeast and south of the plant, and NO_3 concentrations of 0.03 to 0.04 $\mu g/m^3$ south of the plant are predicted for year 2000 emissions with SO_2 and NO_x emission controls in operation at the plant. The modeled concentrations represent about a 65 to 70% decrease relative to the annual average of secondary $PM_{2.5}$ contributed by the Centralia Plant with no additional emission controls (Ref. 40, App. C).
c. The population-weighted annual average primary and secondary particulate matter concentration over the entire modeling domain is predicted to be 0.03 $\mu g/m^3$ for projected 2000 population levels and a 90% reduction in SO_2 emissions and a 30% reduction in NO_x emissions compared to the no control case (Ref. 40, p. 48 and Table 6).
d. The modeled secondary $PM_{2.5}$ aerosol concentrations are all substantially below the new $PM_{2.5}$ standards of 65 $\mu g/m^3$, 24-hour average and 15 $\mu g/m^3$, annual average.

5.4.2 Human Health Effects

Reduction of PM emitted directly from the Centralia Plant will not cause a significant reduction in health effects. However, the control of SO_2 and NO_x emissions will reduce the formation of the secondary particles sulfate and nitrate, both fine aerosols assumed to be less than 2.5 μm in diameter. The risk assessment identified sulfates as the largest component of total particulate concentrations, with secondary nitrates and primary particles emitted directly from the plant as smaller components.

In the Samet et al. 1997 study entitled "An Assessment of the Health Risks Due to Air Emissions from the Centralia Power Plant", emissions from the Centralia Plant were modeled to generate hourly and annual pollutant concentrations for a grid of points in a region within 150 miles of the plant stretching roughly from Bellingham, Washington to Salem, Oregon. The health effects assessed in this study arise from exposures to particles, including acidic particles sulfate (SO_4) and nitrate (NO_3), as well as gaseous SO_2. All of the SO_4 and NO_3 fine aerosol is assumed to be less than 2.5 μm in diameter and is mostly combined with ammonium cations (Ref. 40, p. 6-7). This section describes the estimated effects after SO_2 and NO_x emission controls are in place at the Centralia Plant. See '5.1.2 for a discussion of effects without additional emission controls.

Modeled pollutant concentration increments were combined with population data to produce increments in exposure. The population exposure increments were combined with risk coefficients describing the mortality or morbidity associated with the pollutants to characterize the risk from plant emissions. The risk estimates for mortality and morbidity associated with the Centralia Plant should not be construed as actual mortality and morbidity, but may be used for comparing to estimated risks from other air pollution sources (Ref. 40, p. 63). Health impacts were summarized as follows:

a.The risk of premature mortality from the plant is estimated throughout the study area to be 1.2 to 13.0 with 90% SO_2 emission reduction and 30% NO_x emission reduction depending on the assumptions selected for estimating risk. For King County alone, the study projected, using the same methodology and 1990 data, a risk of premature mortality due to all air pollution based on current ambient measurements of 2,053 annually (Ref. 40, pp. 7 and 64).

b.Using rates provided by the National Center for Health Statistics, the study estimated the numbers of emergency room visits and outpatient visits for asthma by county for the year 1990. Visits attributable to Plant operations represent a very small proportion of the total (Ref. 40, p. 64).

c.Emergency room and doctor office visits estimated to result from plant emissions range from 26 to 41 once SO_2 controls are installed. This compares with an estimated total of 260,000 asthma-related visits each year in the study area (Ref. 40, p. 61 and Table 18).

d.Exposures to air pollution resulting from Centralia Plant emissions for 5.5 million people residing within a 150-mile radius of the plant were estimated with a state-of-the-art pollution model. Compared to the population's total exposure to air pollution, the Centralia Plant is a minor contributor even without SO_2 controls, and its contribution is substantially reduced with the addition of pollution controls (Ref. 40, p. 65-66).

5.4.3 Visibility Improvement

Conclusions from the PREVENT and IMPROVE reports, which analyzed monitored PM values in and around Mount Rainier National Park and other Class I areas in Washington and considered the actual PM emissions from the Centralia Plant, did not identify a significant impact on visibility due to emissions of primary particulate from the Centralia Plant. The majority of the impacts on visibility were attributed to sulfates, nitrates, and organics. Marginal improvements in primary PM capture by the Centralia Plant emission control system will not appreciably change the visibility impairment at Mount Rainier National Park and surrounding Class I areas. Improvement in visibility through reduction of sulfate aerosols attributable to the Centralia Plant is accomplished through reductions in SO_2 emissions, and is described in '3.4.3 Impact of Additional SO_2 Controls on Air Quality, Visibility Improvement.

The expected SO_3 concentration entering FGD absorber vessels is expected to not exceed 10 ppm, so no visible acid mist plume is anticipated from the Plant stack. No visible emissions are expected from use of higher sulfur coal in conjunction with FGD emission control. Potential flue gas conditioning will not affect the Centralia Plant=s impact on visibility in nearby Class I areas.

5.4.4 Odor and Other Nuisance Issues

Since no complaints have been received by SWAPCA in regards to odors issues from particulate matter emissions from the Centralia Plant, any marginal improvement in PM emission control is expected to continue not causing any odor nuisances. Improvement of PM control systems does not require the use of any odor-producing reagents.

5.4.5 Other Environmental Effects of PM

Deposition of primary PM is not expected to change appreciably from marginal improvement in PM emission control. However, improved operation of the PM control system will ensure continued negligible environmental impact from PM such as from deposition. Fine particulate matter includes acidic species such as sulfate and nitrate which contribute to acid deposition when removed from the atmosphere by dry and wet deposition. Since these species are secondary aerosols formed in the atmosphere by conversion of gaseous pollutants SO_2 and NO_x, the environmental effects of these aerosols are discussed in '3.4.5, '4.4.5, and '4.4.6 which address the impacts of SO_2 and NO_x emissions controls.

5.5 Costs of the PM Emission Controls

5.5.1 Elements of Total Capital Costs

The cost for retrofitting a pulse-jet baghouse in place of an ESP is about $30 million total for both units. Sargent & Lundy estimated this cost based on data from an EPRI study and the impact of unit size on the cost of retrofitting a baghouse. Depending on the degree of retrofit difficulty, the cost may vary by ∀30% (Ref. 42). After the cost of basic equipment and installation, the next largest item is a booster ID fan for each unit, required due to increased pressure drop in the PM control system. The cost is estimated based on Sargent & Lundy's FGD study to be about $5.1 million for both units (Ref. 29, Appendix F, Attachment 4). Gas conditioning costs using a sulfur burner to add SO_3 to the flue gas are based on a recent installation at PacifiCorp's Naughton Plant (Ref. 29, Appendix F, p. 13).

5.5.2 Elements of Annual Operating Costs

The O&M cost of a baghouse is estimated based on a cost ratio of baghouse to ESP of 1.7 according to vendor ABB. This results in an incremental fixed O&M cost of approximately $175,000 per year, or $0.13/kW per year. Assuming an additional pressure drop of 6" w.c. for the pulse-jet baghouse relative to the current ESP configuration, the extra energy consumed by the ID fan costs about $0.03/MWh in variable O&M costs (Ref. 29, Appendix F, Attachment 4). Relative to continued operation of the ESPs, the operating costs for flue gas conditioning and baghouse retrofit were determined to be (Ref. 29, p. 140):

	Flue Gas Conditioning	Baghouse Retrofit
Added Fixed O&M	$44,220	$229,944
Added Variable O&M	$75,924	$325,388
Total Incremental O&M	$120,144	$555,332

5.5.3 Cost Discussion

The primary consideration of the economic impact analysis is to compare the capital and annual operating costs and the relative cost effectiveness of implementing the available and technologically feasible emission control options. Cost effectiveness ($/ton reduced) can be used to compare alternative controls for the source in question. However, the EPA does not favor making any presumption that control options with cost effectiveness above or below some arbitrary level are reasonable or unreasonable. The affordability of implementing a control option should generally not be considered in the economic impact analysis because affordability is highly subjective. Emission control options should not be eliminated solely on the basis of economic parameters that indicate they are not affordable by the source. A source should present fixed and variable cost data to show how emission reduction technology affects its ability to operate (Ref. 26, p. 2-7). Installation of some type of FGD system along with continued use of the ESPs will achieve a small improvement in PM emission control, but the cost of this option is counted only as an SO_2 emission reduction cost. The total levelized annual costs for the PM options considered in this RACT analysis, and corresponding cost effectiveness for added emission control benefit are summarized as follows (Ref. 29, pp. 129 and 140):

PM RACT Option	Levelized Annual Cost ($/year)	Incremental Emissions Reduced (tons/year)	Effectiveness ($/ton reduced)
Continued ESPs w/ FGD	$0	265	$0
Flue Gas Conditioning	$555,534	319	$1,741
Baghouse Retrofit	$5,964,725	607	$9,827

5.6 PM RACT Determination and Conclusions

RACT for PM is determined to be the present dual ESP configuration as employed at the Centralia Plant. Based on the emission levels as achieved in practice by this dual ESP configuration, a PM RACT emission limit of 0.010 gr/dscf and 20% opacity is established. This limit is more stringent than the current limits of 0.06 gr/dscf and 20% opacity but will not effectively result in actual long-term emission reductions. Front half only (EPA Method 5) emissions for the last 8 years have averaged 0.002 gr/dscf for Unit #1 and 0.005 gr/dscf for Unit #2. However, the newly established limits will provide better enforceability of good operations and maintenance practices if the control equipment is allowed to degrade in performance.

The establishment of a RACT emission limit must consider technological and economic feasibility. Reasonableness implies that similar sources bear similar costs for emission reductions. The availability and performance capability of control technologies are based, to a large extent, on actual operating experience. In the case of the Centralia Plant, the operating experience with the its unique dual ESP configuration indicates that high reduction efficiencies of 99.9% or greater are achievable for capture and removal of primary, non-condensible PM emissions. Based on a review of the previous eight years of test data, the RACT limit was met on a consistent basis with great margin with one exception.

The use of the current ESPs in series is a unique combination of control technology not found anywhere else in the nation. The efficiency of this control strategy provides a 99.9%, or greater, reduction efficiency for primary PM, which is comparable to efficiencies required of new plants installed under current new source permitting requirements. SWAPCA recognizes that this unique control strategy is uncommon and due to cost and engineering considerations is not likely to be duplicated by other sources. This control technology configuration resulted from a design limitation in the original ESP installation. The emission limit established under the original approval was based on a single ESP per unit and the manufacturer=s guarantee for that equipment. With the addition of the second ESP on each unit, the capture efficiency of this emission control strategy greatly exceeds the expected performance of the original single ESP configuration.

Compliance with the new stack concentration limit shall be based for each unit on EPA Method 5 testing (front half only) on an annual basis. The visible emission limit shall be based on a continuous opacity monitoring system (COMS) if not interfered with by entrained moisture in the stack gas, and evaluated as discrete 6-minute averages (10 such periods each hour) consistent with the NSPS for electric utility boilers and the SWAPCA standard at SWAPCA 400-040.

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Section 6.0

CO RACT EVALUATION

6.1 Impact of CO Emissions on Air Quality

6.1.1 Facility Emissions

Emission inventory data and the RACT submittal from the Centralia Plant owners indicated that CO emissions from the Centralia Plant for calendar years 1993, 1994, 1995, and 1996 were 1678, 1791, 1147, and 1371 tons per year for boilers #1 and #2, combined, under normal operations. Historical emission concentrations have been measured periodically by stack test and have averaged approximately 20 to 30 ppm. Source test emission data from 1996 provided results of 1.1 ppm @ 15% O_2 for Unit #1 and 28.0 ppm @ 7% O_2 for Unit #2. Concentrations vary significantly hour to hour depending on numerous factors. Many of the factors that influence NO_x concentrations also influence CO. These factors include excess air levels, boiler cleanliness, flame temperatures, load changes, fuel composition, coal mill operation (coal flow rate, number in service, fineness settings, primary air flow rates), unit load, and boiler design factors. Typically factors that decrease NO_x emissions, such as low excess air levels, can, if taken to extreme, create conditions that generate high CO levels. The use of good combustion practices requires a compromise between minimizing NO_x emissions while maintaining acceptable CO levels.

It is likely that low NO_x burners will be installed to control emissions of NO_x from the Centralia Plant. Installation of these low NO_x burners will likely result in an increase in CO emissions. Early estimates indicate that CO emissions may double over current emissions from the facility. Even though such emissions are not expected to cause an adverse ambient impact or health risk, additional operator emphasis will be necessary to ensure good combustion within the boilers to minimize emissions of CO. High emissions of CO are indicative of poor combustion. Poor combustion results in increased fuel consumption and more fuel cost for the facility. Therefore, there is substantial economic incentive for the boilers to be operated at maximum combustion efficiency (low CO). One point demonstrating the importance of CO monitoring to efficient operation is that each boiler is equipped with three CO monitors. One CO monitor is installed as part of the stack gas monitoring equipment; the other two are located in each of the two boiler discharge ducts.

Review of data from 1985 to 1994 and projections to 2006 indicates the CO inventory for western Washington is dominated by on-road mobile sources which comprise 65 percent of the inventory (Ref. 30, p. 14).

6.1.2 Ambient Levels of CO

A National Ambient Air Quality Standard (NAAQS) has been established at 40 CFR 50.8 for carbon monoxide (CO) at 35 parts per million (ppm) 1-hour average and 9 ppm 8-hour average. Any CO value monitored above this level is considered an exceedence. Two exceedences within one calendar year is considered a violation. If an area is in violation of the standard, it is considered a nonattainment area. Experience has demonstrated that the 8-hour average is the more likely of the two standards to be exceeded. 40 CFR 50.8 also contains reference methods for measuring CO concentrations in ambient air, procedures for averaging data to determine 8-hour concentrations, and requirements regarding presentation of data. In addition, EPA has also issued guidance which specifies that two complete consecutive years of quality-assured ambient monitoring data with no violations of the NAAQS must be collected before an area can be considered to have attained the standard.

In addition, 40 CFR Part 50.8 also defines how ambient air quality monitoring data are to be compared to the applicable NAAQS. It states that all monitoring data should be expressed to one decimal place, and indicates that standards defined in parts per million should be compared "in terms of integers with fractional parts of 0.5 or greater rounding." This led to an interpretation by EPA that any 8-hour CO concentration of less than 9.5 ppm would be equivalent to attainment. This rounding convention is therefore used for CO monitoring data to demonstrate maintenance with the CO NAAQS.

Washington State University conducted an air monitoring study before and after the startup of the Centralia Plant at four sites near the Centralia Plant from 1968 to 1974. Average sulfates, particulate matter, and NO_x levels were monitored, however, CO was not monitored.

The SWAPCA Annual Reports for 1994, 1995, and 1996 have summarized CO emissions from each of the respective counties of jurisdiction. Industrial emissions of CO for Lewis County were estimated at 3183 tons per year for 1994, 1810 tons per year for 1995, and 2367 tons per year for 1996. Total CO emissions in Lewis County were estimated at 36,791 tons per year for 1994, 30,947 tons per year for 1995, and 45,862 tons per year for 1996. The Centralia Plant CO emissions account for approximately 4.8% of the total inventoried CO emissions in Lewis County for each year.

CO ambient values are monitored in Tacoma by the Puget Sound Air Pollution Control Agency (PSAPCA). Values reported for 1995 and 1996 for the high one-hour maximum were 10.6 ppm and 11.4 ppm, respectively, and for the eight-hour maximum were 6.9 ppm and 7.3 ppm, respectively for 1995 and 1996.

There are two CO monitors in the Olympia area, one monitor is located at the Olympic Air Pollution Control Authority (OAPCA) office in Lacey and the other is located in downtown Olympia. The downtown Olympia monitor (Oddfellow) ceased operation in May 1996. The Lacey monitor started operation in January 1996. Values reported for 1996 for the OAPCA (Lacey) location for the high one-hour and eight-hour maximums were 10.0 ppm and 7.5 ppm, respectively. Values reported for 1995 and 1996 for the downtown Olympia location for the high one-hour maximum were 12.9 ppm and 17.4 ppm, respectively, and for the eight-hour maximum were 6.0 ppm and 4.7 ppm, respectively.

The 1994 Annual Report for the Puget Sound Air Pollution Control Agency (PSAPCA) reported CO emissions for the four county area as 917,000 tons per year, with on-road motor vehicles as the largest single category. The Seattle-Tacoma urban area, 50 miles north of the Centralia Plant, was classified as a non-attainment area for carbon monoxide based on previous years monitoring data. However, in recent years there have been no exceedences of the ambient air standard. The Seattle-Tacoma area was redesignated as attainment by EPA in October 1996.

The Vancouver, Washington area is located approximately 70 miles south of the Centralia Plant and has two CO monitoring sites. The site located at the intersection of Fourth Plain Boulevard and

Fort Vancouver Way, known as the Atlas & Cox site, has been in operation since 1987. The site located at the intersection of Highway 99 and NE 78th Street, known as the Hazel Dell site, was recently installed and started operating in the summer of 1995. Prior to 1987, there was a CO monitoring site located at Justin's Photo on Evergreen Boulevard between Main Street and Broadway which operated from 1978 to 1986.

The SWAPCA CO monitors run continuously with one-hour and eight-hour averages derived electronically via data loggers and integrators. After rigorous quality assurance, the data is input into the Aerometric Information Retrieval System (AIRS) which provides EPA with SWAPCA's air quality monitoring data.

The Vancouver area has attained the carbon monoxide NAAQS based on air quality monitoring data from the Atlas & Cox site from 1992 through 1993 and has continued to attain the standard since that time. In addition to the two permanently located CO monitors in Vancouver, other CO data is periodically obtained from saturation studies. A saturation study involves the collection of CO concentration data on a limited basis with integrated bag samples to obtain information about CO concentrations over a wide ranging area. SWAPCA performed a saturation study the winter of 1993-1994 which verified that the Atlas & Cox site was consistently the highest reading site for the area and provided further evidence that the Vancouver area is in attainment of the NAAQS.

There are no permanent CO monitors in the vicinity of the Centralia Plant. Emissions of CO from the Centralia Plant were modeled by PacifiCorp to determine ambient impact of CO in the area of the Centralia Plant. On-site meteorological data was collected at the Centralia Plant in 1990 by AeroVironment. The model utilized for this exercise was identified as ICST3 with a twenty kilometer receptor grid. The CO rate used in the model was 28 grams per second. This value is based on maximum boiler load for a full year. The model reported 19.4 $\mu g/m^3$, the highest one-hour concentration, and 4.9 $\mu g/m^3$, the highest 8-hour concentration. The highest one-hour concentration impact was reported in the general vicinity surrounding the plant and within a few miles of the plant. Based on this data, there is no long range transport phenomena that would suggest the Centralia Plant contributes significantly to ambient levels in the Seattle-Tacoma or Portland-Vancouver areas. The federal and state ambient air quality standard for CO is 9 ppm (10,300 $\mu g/m^3$) 8-hour average, and 35 ppm (40,000 $\mu g/m^3$) 1-hour average.

The lack of documented ambient impacts from CO emissions should not be the sole consideration for the purpose of making a RACT determination and establishing an appropriate RACT emission limit. Lack of significant ambient impacts and still requiring consideration for new or modified sources is supported by EPA decisions (1989 WL 266361 (EPA)) (Ref. 31) in PSD BACT cases. The same logic applies to RACT determinations; however, the emission standard is tempered more by the effect of energy, environmental, and economic collateral impacts, resulting in a less stringent standard than is obtained from BACT.

6.1.3 Human Health Effects of CO

Carbon monoxide is a colorless, odorless and tasteless gas which replaces the oxygen in the body's red blood cells through normal respiration. Exposure to high levels of CO can slow reflexes, cause confusion and drowsiness, and in high enough doses and/or long exposure, can result in death. People with heart disease are more susceptible to develop chest pains when exposed to high levels of CO. The major human-caused source of CO is incomplete combustion of carbon-based fuels.

The major source is primarily from gasoline-powered motor vehicles. Other important sources are wood stoves, open burning and fuel combustion in industrial and utility boilers. Most serious CO problems occur during the winter in urban areas, when CO is trapped near the ground by atmospheric inversions.

Modeled values of CO in the area surrounding the Centralia Plant are extremely low; data reported indicates that the highest values are less than 1% of the one-hour and eight-hour air quality standards. Based on this data, there are no perceived health effects from CO emissions in the immediate area or surrounding area of the Centralia Plant. In addition, there are no known reported health impacts from Centralia Plant emissions.

The health impacts study performed by Samet et al. of Johns Hopkins University did not include an evaluation of exposure to, or health effects of, CO.

6.1.4 Visibility Impairment

Visibility impairment is caused by the scattering and absorption of light by suspended particles and gases. Three pollutants (primary particulates, NO_x and SO_2) have been identified as the primary contributors to visibility impairment. CO has not been identified to be a contributor to visibility impairment, therefore no impact or impairment is projected and further analysis has not been performed or required (Ref. 33, p. 3).

6.1.5 Emission Limit Violations

The New Source Performance Standard (NSPS) for electric utility boilers at 40 CFR 60.40 et seq. (Subpart D and Subpart Da) does not include a standard for CO. There was no CO limit established for the Centralia Plant under the original construction approval or subsequent Order issued by SWAPCA and there is no state or local limit established for CO other than the ambient air quality standard. Therefore, because there is no established limit, there has been no violation of a state or local limit. Further, based on modeling results, there has been no violation of the state and federal ambient air quality standard as a result of CO emissions from the Centralia Plant.

Based on modeling of ambient CO concentrations from Centralia Plant emissions, no long range transport phenomena were discovered that would suggest the Centralia Plant contributes significantly to ambient CO levels in the Seattle-Tacoma or Portland-Vancouver areas. Modeled values of CO in the area surrounding the Centralia Plant are extremely low; data reported indicates that the highest values are less than 1% of the one-hour and eight-hour air quality standards.

6.1.6 Odors and Other Nuisance Issues

Carbon monoxide is a colorless, odorless, and tasteless gas. Due to the inherent nature of this gas there are no off site odors that could be observed or reported.

6.1.7 Environmental Effects of CO

The EPA has established a primary ambient air quality standard to protect the public health (human health). Secondary air quality standards are established by EPA to protect the public welfare from impacts of individual air pollutants. Public welfare impacts include environmental impacts. EPA has not established a secondary ambient air quality standard for CO because there is no significant public welfare impact from CO. Ambient CO will oxidize to carbon dioxide (CO_2) in the atmosphere over time. Carbon dioxide does not cause the health effects associated with CO, although it is a greenhouse gas which has been shown to cause global warming (see major Section 2). Therefore, there is no known adverse or other environmental effect from CO emissions from the Centralia Plant.

6.2 Availability of Additional CO Controls

Currently, "good combustion controls", or "good combustion practices", or "good operating practices" are currently employed at the Centralia Plant to limit emissions of NO_x. Good operating practices that are employed to minimize NO_x increase the variability of CO emissions. The practices which have been identified to control NO_x emissions include monitoring plant parameters and specific operator actions such as: (1) Excess air levels - boiler demand setpoint adjustment to target CO levels to less than 50 ppm; (2) Mill out of service - top mill is operated out of service when possible to provide excess overfire air; (3) Simulated overfire air -auxiliary air dampers on top two mills manually operated to provide excess overfire air; (4) Boiler cleanliness - wall soot blowers are used to reduce hot spots thereby reducing NO_x; and (5) Burner tilt - normally operated in horizontal position to maintain good mixing in the furnace.

The EPA's RACT/BACT/LAER Clearinghouse lists control technology for CO for BACT and/or PSD determinations but none for RACT for coal combustion sources. The control technology identified is the use of good combustion practices, combustion controls, and boiler design and operation. This control strategy has been identified to meet BACT and PSD requirements in recent years. Additional technology is available for non-coal fired applications such as CO oxidation catalysts, however, no application of post-combustion controls has been identified on coal-fired sources, even on a pilot or demonstration basis. Post combustion controls for CO would have to overcome issues of particulate loading and sulfation in addition to proper temperature and moisture conditions for a particular technology. Relating costs for other combustion sources for control of CO indicates that, if it were possible, the cost would be prohibitively high. At this point in time, good combustion controls is the only feasible control option that is commercially or economically available. There are no known instances where post-combustion technology has been implemented on a tangentially fired coal boiler.

As noted in the Air Pollution Engineering Manual (Ref. 77, p. 217) the following was provided: "The VOC and CO emissions per unit of fuel fired are normally lower from pulverized-coal or cyclone coal furnaces than from smaller stokers and hand-fired units where operating conditions are not so well controlled. Measures used for NO_x control can increase CO emissions, so to reduce the risk of explosion, such measures are applied only to the point at which CO in the flue gas reaches a maximum of about 200 ppm. Other than maintaining proper combustion conditions, control measures are not applied to control VOCs and CO." Ed Levy of Lehigh University states in a recent paper in CO Emission Levels in Boilers, "For CO to be a flammability hazard, the level must exceed 125,000 ppm. It is highly unlikely to find CO levels this high outside of the combustion zone in the furnace." High CO levels up to 200 ppm is an indicator of poor combustion which may also indicate potential areas having conditions that will result in waterwall tube wastage.

6.3 Emission Reduction to be Achieved by Additional CO Controls

6.3.1 Effectiveness of CO Control Options

The "effectiveness" of "good combustion practices" is difficult to place an exact value on because of the numerous interrelated process controls and the fact that other pollutants such as SO_2 and NO_x are of greater concern, whereby controlling or minimizing emissions of those pollutants may have a negative impact on CO emissions. Because emissions of CO are significantly less than NO_x or SO_2, process (combustion) controls can have a larger impact on emissions of those pollutants. This analysis is best represented as which combination of NO_x and SO_2 controls have the least negative impacts on CO emissions. These considerations are included under the evaluation of the control options for the other pollutants in Sections 3.0 and 4.0. In addition to add-on control technology for NO_x and SO_2, combustion controls can impact emissions of other pollutants.

Only one other technology has been identified as a potential technology for controlling emissions of CO. That technology is an oxidation catalyst, hot side or cold side. Each application has technical constraints that render the technology generally infeasible. This technology has the potential to reduce CO emissions as implemented on other source categories by approximately 90% if technical uncertainties could be overcome. Issues to be resolved include poisoning of the catalyst by heavy metals and halogenated compounds, sulfation inhibition (sulfur poisoning of the catalyst), and particulate loading of the catalyst. Installation would probably require modifications to the induced draft fans because of increased backpressure, natural gas-fired duct burners and flue-gas to flue-gas heat exchangers to maintain inlet temperatures. Because there are no installations of this type in the US or other developed countries, only theoretical information is available.

The most significant issue surrounding CO emissions is the potential doubling of CO emissions due to installation of combustion modifications for reduction of NO_x emissions. In an average year when CO emissions under the present plant configuration would be 1500 tons/yr, emissions of CO following installation of low NO_x burners could be 3000 tons/yr. A 1500 ton/yr increase is significantly over the PSD significance threshold of 100 tons/yr. Modeled values at a stack emission concentration of 60 ppm indicate no significant or adverse environmental impacts are expected. In a situation where such an increase would not be the result of a pollution control project as defined in 40 CFR 51, such an increase would be considered significant for PSD purposes.

6.3.2 Effect of Options on Other Air Pollutants

Only two technologies have been identified as potential technologies and only the "good combustion practices" option is currently feasible for the Centralia Plant. The "good combustion practices" technology option has the potential to result in small increases or decreases in other pollutants depending on the combustion control option selected. In general, CO is the lesser pollutant of concern, in that the quantity of emissions of CO is far less than NO_x and SO_2, therefore controls evaluated for those pollutants would dominate consideration of effectiveness of individual "good combustion practices". The technology option of "good combustion practices" on an individual control basis, could have significant impacts on other pollutants. For example, too much excess air in the combustion zone in the furnace can contribute to "slagging" in the furnace, resulting in hot spots and increasing NO_x emissions. Operating with the top coal mill out of service when conditions allow and keeping the auxiliary and fuel air dampers open increases overfire air and can reduce temperatures and therefore NO_x emissions. "Good combustion practices" are currently employed at the Centralia Plant.

Good combustion practices is focused on obtaining and maintaining the optimal combination of air and fuel supplied to the boiler. Too much excess air results in elevated exhaust temperatures which contributes to the formation of NO_x. Energy loss from excess air (oxygen) increases with temperature, meaning that the higher the temperature of the exhaust gas, the greater the loss of energy from unnecessary air being heated up in the boiler and discharged from the flue. On the other hand, it is more wasteful to burn with excess fuel; i.e., too little combustion air. Only the amount of fuel needed to reach a stoichiometric balance with the available oxygen will burn in this scenario, sending unused fuel (and other pollutants such as particulate matter and volatile organic compounds) up and out the stack. Energy, as well as fuel, is wasted in this scenario. Generally, oxygen levels much below 1% can result in significant increases in emissions of CO and can result in explosive levels of combustibles.

A potential doubling of the CO emissions is likely due to installation of low NO_x burners. However, the importance of reducing NO_x emissions greatly exceeds the significance of the anticipated CO emissions increase. An emission limit is still prudent because CO PSD increments are being exceeded by such a substantial amount due to the pollution control project.

6.3.3 Other Environmental Impacts

6.3.3.1 Water Quality
The "good combustion practices" that have been identified do not result in the use of water or the generation of waste water. In addition, if an oxidation catalyst were to be proposed, there would not be a water quality impact.

6.3.3.2 Solid and Hazardous Waste
The "good combustion practices" that have been identified do not result in the use of water or other chemicals that would result in the generation of additional solid or hazardous waste from current plant operations.

6.4 Impact of Additional CO Controls on Air Quality

6.4.1 Ambient Levels of CO

No CO control options are considered to be feasible beyond good combustion practices, so no impact is expected from CO controls.

6.4.2 Human Health Effects

No CO control options are considered to be feasible beyond good combustion practices, so no impact is expected from CO controls.

6.4.3 Visibility Improvement

No CO control options are considered to be feasible beyond good combustion practices, so no impact is expected from CO controls.

6.4.4 Emission Limit Violations

No CO control options are considered to be feasible beyond good combustion practices, so no impact is expected from CO controls.

6.4.5 Odors and Other Nuisance Issues

No CO control options are considered to be feasible beyond good combustion practices, so no impact is expected from CO controls.

6.4.6 Environmental Effects of CO

No CO control options are considered to be feasible beyond good combustion practices, so no impact is expected from CO controls.

6.5 Costs of the CO Emission Controls

6.5.1 Elements of Total Capital Costs

No CO control options are considered to be feasible beyond good combustion practices, so no impact is expected from CO controls.

6.5.2 Elements of Annual Operating Costs

No CO control options are considered to be feasible beyond good combustion practices, so no impact is expected from CO controls.

6.5.3 Cost Discussion

No CO control options are considered to be feasible beyond good combustion practices, so no impact is expected from CO controls.

6.6 CO RACT Determination and Conclusions

Carbon monoxide is a pollutant of concern because the number of tons of CO produced each year after the installation of combustion modifications to reduce NO_x will likely double. CO emissions will increase approximately 1500 tons/yr depending on capacity factor and other plant operating parameters, and will therefore greatly exceed the PSD significance threshold of 100 tons/yr.

Based on the lack of other feasible technologies for control of CO emissions, RACT is considered to be the current practice of "good combustion practices". Emission levels that can be achieved with this technology are in the range of 50 to 200 ppm, annual average, during normal operations. RACT for emissions of CO is therefore determined to be a concentration not to exceed 200 ppm on an annual average (calendar year), both units combined, using existing plant operating data to identify average CO concentrations. For information purposes, year-to-date average carbon monoxide concentrations shall be calculated and reported quarterly. Plant operating data collected by the CO monitors shall be validated once per year, for each stack (flue), by source testing, using EPA Method 10, to confirm the representativeness of the CO plant data.

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Section 7.0

COLLABORATIVE DECISION MAKING PROCESS COMPARISON WITH BEST AVAILABLE RETROFIT TECHNOLOGY (BART) GUIDELINES

The following section is provided to describe the outcome of the collaborative decision making (CDM) process relative to the best available retrofit technology (BART) guidance document (Ref. 33) criteria and the RACT Technical Support Document. While the CDM group acknowledged that the outcome of the negotiations was not focused on achieving compliance with BART criteria, the CDM group considered the BART criteria in the late stages of negotiations. The CDM group also acknowledged that, even though a formal BART determination was not performed by the group, upon evaluation of the BART criteria, the CDM Target Solution provided substantial SO_2 and NO_x emission reductions which were representative of the types of reductions that are envisioned in a BART determination. The CDM group also considered the negotiated solutions for the Navajo Generating Station (Arizona - Grand Canyon) and the Hayden Station (Colorado - Mt. Zirkel). The target solution proposed by the CDM group was similar to the outcomes of the other negotiated solutions, and was considered by many in the CDM group to represent a BART solution. Considerations and evaluations as documented by the CDM group are contained in Appendix A of this Technical Support Document.

The following comparison is provided to identify the major criteria of the BART guidance document and describe the activities of the CDM group that address these criteria. In addition, SWAPCA has provided reference to the sections of the Technical Support Document that evaluate the control technologies that would be required in a BART determination. While the evaluation in this Technical Support Document has been performed to establish emission limits under the provisions of RCW 70.94.154 for Reasonably Available Control Technology (RACT), many of the evaluations required under a BART determination are the same. The following evaluation provides those cross references between the RACT and BART process and the criteria that was considered by the CDM group.

BART Criteria	**CDM Activity**
I. Determination of Visibility Impairment	
The certifications, in general, describe uniform visibility degrading regional haze, and in one instance specifically say not plume blight. However, there is general agreement in the regulatory community that because of the significant quantity of SO_2 emissions from the Centralia Plant, that, by inspection, it was reasonable to assume that the SO_2 emissions form the Centralia Plant would likely contribute to visibility impairment during certain episodes. (Ref. 30, Appendix A)	The CDM group was made aware on several occasions of the visibility impairment certifications that were made by the FLMs.
A. Pollutants of Concern	
The pollutants of concern established for purposes of BART for the Centralia Plant would likely be particulate matter (elemental carbon) and sulfate and nitrate aerosols thereby implicating SO_2 and NO_x emissions.	The CDM group was informed by the Federal Land Managers that visibility impacts within Mount Rainier National Park were due mostly to sulfates in the ambient air and to a lesser degree, nitrates and particulate matter. In addition, there was concern about acid deposition in sensitive lakes within the Park. Other pollutants were agreed to not contribute to visibility impairment.
b. Phased Program	
Congress and EPA established a phased approach to remedying visibility impairment. Phase I focuses on controlling those sources which can currently be identified as causing visibility impairment by means of visible plumes, and single source haze. As scientific and technical understanding of source/impairment relationships improve, future regulations will address more complex forms of visibility impairment such as regional haze and urban plumes, Phase II (Regional haze Regulations - FR Volume 62, Number 147 - July 31, 1997).	
II. Identification of Source(s) Impairing Visibility	
A. Federal Land Manger Identifies Visibility Impairment (Ref. 30, Appendix A)	The CDM group was made aware on several occasions of the visibility impairment certifications that were made by the FLMs.
B. State or Local Determines Facility That is Reasonably Attributable - No determination has been made by SWAPCA or WDOE	

C. Source May Apply for Exemption - No exemption has been filed by Centralia Plant

III. Visibility Impact Analysis
Will the imposition of retrofit controls improve visibility?

A. Source Data
i. Collect appropriate data; plant size, capacity, etc.

ii. Estimate current emission rates.

B. Preliminarily assess improvement in visibility expected from retrofitting: Compare existing visibility (based on existing emissions) with the visibility anticipated from imposition of maximum achievable control; i.e. NSPS. Use analytical techniques and empirical methods to estimate degree in improvement in visibility in association with primary particulates, oxides of nitrogen and sulfur dioxide.

i. If, after comparison of the visibility at existing and maximum achievable control levels, no perceptible improvement, or if BART emission limitations equivalent to NSPS are imposed, the analysis need not continue.

ii. If visibility is expected to improve as a result of controls, available retrofit technology should be analyzed so that emission limits representing BART can be established, i.e., engineering analysis.

At one of the initial meetings, participants of the CDM group identified desired outcomes for the voluntary process. The list below reflects individual statements and does not necessarily represent consensus of the group.
1. Better emission controls than that provided by the 1995 SWAPCA RACT Order.
2. Balance of economic impacts and environmental benefits.
3. Achievement of maximum emission reductions without shutting down the plant.
4. An enforceable annual emission limit.
5. Protection of air-quality-related-values on public and private lands.
6. Emission reductions should be cost effective using proven technology.
7. Create a long-term solution.
8. Demonstrate that a voluntary, cooperative group such as CDM can succeed.

The CDM group collected and evaluated appropriate data which it needed to arrive at a target solution for the Centralia Plant. The Centralia Plant owners came to the CDM meetings knowing that they would need to make all such data readily available. This included power plant data, current emission data, and forecasted emissions under various control options. It was also understood by the CDM participants that to facilitate the sharing of information and closely evaluate the economics of the power plant affecting a shut down it may be necessary for the CDM group to be briefed on plant information. The CDM group's objective was to learn as much about the sulfur dioxide emission reductions which this power plant could achieve as possible.

The 1995 SWAPCA RACT Order was available to all CDM participants. This document provided the necessary plant and emissions data from which to start. Based on the PREVENT study and modeling performed by John Vimont, the Federal Land Managers indicated that visibility could be improved at Mount Rainier National Park by approximately 1 deciview by making significant reductions in SO_2 emissions at Centralia Plant. An improvement of 1 deciview is considered the minimum increment that may be perceptible. Based on this data the CDM group pursued additional information regarding available control options.

At the outset of the CDM meetings, it was mutually agreed that efforts of the group would focus on achieving the maximum sulfur dioxide emission reduction possible while coming close but stopping short of costs which would cause the power plant to shut down. Thus, significant commitments of time to develop analytical techniques and empirical methods to estimate the degree in improvement in visibility from each possible control option as advocated by the BART guideline format was viewed in the early CDM discussions as being of lesser importance than quickly moving to evaluations of the lowest achievable sulfur dioxide emission reduction options. Agreement was also reached that sulfur dioxide emissions were the primary contributor to visibility impacts in surrounding Class I areas. Nitrogen dioxide was concluded to have minimal impact on visibility reduction in comparison to sulfur dioxide. Particulate matter emissions were recognized by the CDM group to be currently controlled at a 99.9% efficiency and providing no opportunity for significant additional reductions to improve visibility. Participants also agreed to forego and move beyond the BART guideline criteria of engaging in an evaluation of whether there would be any perceptible improvement in visibility after installation of a target solution. Use of the NSPS as a benchmark for meeting BART did not enter the discussion until late in the process when 90% removal was seriously discussed. These steps in the BART guideline criteria were not allowed to impede progress on the negotiations while all parties preserved their legal rights to pursue such actions if the negotiations failed. The focus was on doing the "right thing" for the environment rather than causing the preliminary steps in BART guideline document to be addressed through litigation.

C.Engineering Analysis

i.Cost of Compliance

ii.Time Necessary for Compliance

iii.Energy and Nonair Quality Impacts

iv.Existing Technology

v.Remaining Useful Life of Source

The Centralia Plant owners briefed the other participants to provide a general understanding of the electrical power business including operations of coal-fired power plants, coal mining, available scrubber technology options, electrical power regulation, and possible implications of future deregulation. Regulatory agencies and land managers also discussed and explained their mandates and environmental protection goals. The group worked primarily with 8 potential target solutions which spanned the range from plant and mine closure, to mine closure with substitution of cleaner coal, to 70 percent scrubbing with various phase-in schedules. A 90 percent scrubbing solution did not surface as an option until further cost savings could be identified that

vi. Degree of Improvement Anticipated	would allow the owners to implement such an option while remaining financially viable. A significant cost saving option that was implemented was a tax exemption package that was approved by the Washington Legislature and Governor in 1997.
D. Energy Impact Address energy use associated with control system and assess the direct effects of such energy use on the facility and community. i. Energy Consumption: Source of energy required for control system should be identified and compared. Make comparisons in terms of energy consumption/unit of pollutant removed. ii. Impact on Scarce Fuels: Type and amount of scarce fuels which are required by control equipment should be identified and compared. iii. Impact on Locally Available Coal: Discourage use of fuel other than locally or regionally available coal if it causes significant local economic disruption or unemployment.	Significant energy consumption of the sulfur dioxide control equipment was identified to the CDM group and accepted as necessary to achieve the net improvement in air quality which was desired. The use of scarce fuels by the control equipment was not viewed by the CDM group to be a significant hurdle in the decision making process. On the other hand, the impact on locally available coal of achieving the maximum sulfur dioxide emission reductions received considerable discussion by the CDM group. It was understood that the BART guidelines discourage the use of fuel other than locally or regionally available coal because it causes significant local economic disruption or unemployment. Converting to the use of Wyoming low sulfur coal was acknowledged by the CDM group, after considerable discussion, to provide a major economic hardship for the City of Centralia and Lewis County.
E. Environmental Impact Determine net environmental impact associated with emission control systems. i. Air Pollution Impact: Assess impact of air pollutants emitted from a gas stream or fugitive sources in terms of quantity of emissions or modeling results. ii. Water Impact: Identify quantities of water used and water pollutants produced and discharged as a result of the control system. iii. Solid Waste Disposal Impact: Compare	The evaluation of net environmental impacts associated with the control equipment required by the BART criteria were also discussed. The air pollution impacts of the target solution were clearly viewed as being good for the environment. Solid waste issues were addressed early on by the preference for the control equipment to produce a commercial grade gypsum product to reduce solid waste.

quality and quantity of solid waste that must be stored and disposed of or recycled from the various alternative control systems versus the control system that is considered BART.

iv. Irreversible or irretrievable Commitment of Resources: Consider any trade offs between short-term environmental gains versus the expense of long term environmental losses that the control system may cause.

F. Economic Analysis

Address the economic impacts associated with installing and operating control systems considered for BART.

i. Direct Costs: Present the direct cost for a control method including the following and make comparisons in terms of cost effectiveness ratios.

- Investment costs, operating costs, and annualized costs presented separately.
- Credit for tax incentives.
- Credit for product recovery costs and by-product sales generated from use of control systems.
- Costs of air treatment, water treatment, and solid waste disposal presented separately.
- Costs and useful life of any existing control equipment, if applicable.
- Lifetime of investment.

ii. Capital Availability: Address and fully document the difficulty some sources may have in financing alternative control systems.

iii. Local Economic Impacts: Address the economic sensibility of BART requirements and the impact on production decisions (i.e., reduction of scale of operation, change in production mix).

The economic evaluation analysis portion of the BART guideline was addressed through numerous spreadsheets that were reviewed by the CDM group over the course of the 10 months of CDM meetings. Investment costs, operating costs and annualized costs of the control equipment were evaluated. Discussions also lead to the need for approval of a tax incentives package by the state legislature. Credit was also taken in the cost analyses for by-product sales generated from the use of the sulfur dioxide control systems as mentioned in the BART guideline criteria. Capital availability was evaluated from the perspective of understanding how close the power plant was to being shut down by the accumulation of the control equipment costs and market competitiveness issues. However, this cost issue did not hinder the ability to achieve a significant air quality improvement for the environment by the CDM Target Solution. The recognition that the CDM Target Solution's aggressive reduction in emissions was viewed as satisfactorily addressing the local economic impact criteria under the economic analysis of the BART guideline criteria.

G. Considering Alternative Control Systems

If BART is not set equivalent to NSPS control then a detailed explanation of how the various required BART factors were weighed and reflect a reasonable balance of the BART factors, (i.e., compare visibility, energy, economic and other impacts of NSPS control to impacts of alternative controls).

Even though a BART analysis or determination was not performed by the CDM group, many members of the group indicated that the emission reductions achieved by the target solution were as stringent or more stringent than what might have been determined had a BART limit been established through a formal regulatory process.

IV. BART Selection

SWAPCA has determined that the CDM Target Solution meets or exceeds the requirements of BART.

V. Conclusion

A full BART analysis does not require plant shutdown and neither does CDM.

A draft BART analysis which specified 70% removal was performed for Navajo Generating Station; however, a delay in the date of startup and other financial considerations made possible a negotiated agreement to proceed with 90% SO_2 removal. CDM provides 90% removal without any delays like Navajo received.

CDM Target Solution addresses all of the above BART guideline criteria.

The CDM Target Solution meets or exceeds the requirements of BART.

BART Criteria	CDM Activity	RACT TSD Location

Section 8.0

RACT/CDM EMISSION LIMITS COMPARED TO EPA BART GUIDANCE

This section is provided to document how the RACT/CDM emission limits and the process in establishing these emission limits, compare to emission limits that would be established under the EPA's BART guidance document (Ref. 33). This section does not constitute a BART determination because the state and local regulatory agencies find that the underlying information is insufficient to make a finding of reasonable attribution. The basis for this section comes from two references, PREVENT (Ref. 21) and the Modeling Analysis by John Vimont (Ref. 18) in addition to the RACT submittal document (Ref. 29). SWAPCA was requested by the Centralia Plant, and supported by WDOE, Forest Service, National Park Service and the EPA, to perform a BART-like analysis to determine if the RACT/CDM emission limits would meet or exceed BART criteria. Without assessing the validity of the information as presented in the PREVENT study and the Modeling Analysis, the following analysis was performed for comparison purposes. SWAPCA is not endorsing these documents as being sufficient to draw a conclusion or reasonable attribution. Prior to making a formal declaration of visibility impairment or reasonable attribution under the federal visibility regulations, SWAPCA would require additional monitoring, modeling and analysis to complete a formal BART determination. While the existing documentation provides some insight into the visibility problem, there are several issues that would need to be resolved prior to making a determination. Therefore, SWAPCA, the Centralia Plant, the Federal Land Managers, WDOE and EPA, have agreed to not proceed with a formal reasonable attribution study, but rather to agree-to-disagree on the reasonable attribution, and evaluate the potential visibility improvements as a result of the RACT/CDM emission limits using the PREVENT study and Modeling Analysis as a basis. Therefore, the results presented below likely overestimate the amount of visibility improvement that will actually be achieved by installation of emission control equipment on the Centralia Plant due to uncertainty factors in PREVENT and the Modeling Analysis.

8.1 Plant Description and Control Technologies

In 1980, EPA issued regulations that required states to develop regulatory programs to comply with Section 169A of the Clean Air Act. These regulations were intended to address what EPA considered as Phase I visibility protection criteria. Phase I visibility protection is aimed at eliminating or reducing the impacts of visible plumes or layered haze on integral vistas of mandatory federal Class I areas. As part of the federal legislation, EPA was required to develop guidelines for determining emission limitations representing best available retrofit technology (BART). BART analyses for fossil-fuel fired power plants in excess of 750 megawatts generating capacity are required to use these guidelines in establishing BART emission limits (Ref. 78). These guidelines were issued by EPA in November of 1980 (Ref. 33).

In the preamble to the 1980 visibility protection regulations (40 CFR 51), EPA clearly expected its Phase I regulations to address particulate matter and NO_x emissions, which tend to form visible plumes or single source haze and not address SO_2 emissions. Single source haze causes a general whitening of the atmosphere and reduction of clarity of terrain features. Both forms of impairment when "reasonably attributed" to a source must be regulated under Phase I. In the EPA guidance document, EPA envisioned that SO_2 emissions would be subject to visibility evaluations (regional haze) and BART analyses during the Phase II program since SO_2 emissions tend to form a uniform, regional haze rather than a distinct plume.

Neither the Department of Ecology nor SWAPCA has reasonably attributed the Centralia Plant's emissions as a source of Phase I visibility impairment. Similarly, the operating partner for the Centralia Plant, PacifiCorp, has not agreed that the Centralia Plant causes Phase I visibility impairment.

The normal process involved in making a BART determination begins with the Federal Land Manager (FLM) responsible for a particular mandatory Class I area certifying to the agency with jurisdiction, that there exists impairment of visibility within the Class I area. The FLM may identify to the agency suspected sources causing the visibility impairment. The agency must review the information from the FLM and, utilizing analytical and/or empirical methods, make a determination of reasonable attribution. If a facility reasonably attributes to visibility impairment, the agency must analyze for BART and require that each existing stationary facility required to install BART, do so as expeditiously as practicable but in no case later than five years after plan approval. BART is applicable to sources constructed or modified after August 7, 1962.
The EPA guidance on how to perform a BART analysis starts with the collection of plant data and emission rate estimates. From these data, the agency determines whether the application of the applicable NSPS will result in a perceptible improvement in visibility. This may be done analytically (use of the VISCREEN or PLUVUE visibility models) or empirically (comparison photographic techniques). If, after comparison of the visibility conditions at existing control levels and maximum achievable control levels, no perceptible improvement is expected, the BART guidance indicates that the analysis need not continue. If a perceptible improvement is found, then the agency has two different paths to follow. One path is to impose a BART emission limitation equivalent to the NSPS, write an enforceable Regulatory Order, and modify the Visibility State Implementation Plan (SIP) to require compliance with the NSPS emission limits. The other path involves a detailed technology analysis that accounts for environmental, energy, and economic impacts of various controls. This analysis may result in BART limitations that may be higher or lower than the applicable NSPS limits. Flow charts of this process copied from EPA's guidance manual are attached to the end of this comparison.

When conducting a detailed BART technology assessment according to the EPA guidance (Ref. 33), the agency must consider the energy, environmental and economic implications of the potential control options. The BART guidance requires the following elements be considered in determining what emission limits represent BART for a particular source:

Basic Information
Source Information
Emission Rate Estimates
Preliminary Assessment of Improvement in Visibility
Primary Particulates
Oxides of Nitrogen
Sulfur Dioxide
Engineering Analysis of Alternatives
Energy Impact
Energy Consumption
Impact on Scarce Fuels

Impact on Locally Available Coal
Environmental Impact
- Air Pollution Impact
- Water Impact
- Solid Waste Disposal Impact
- Irreversible or Irretrievable Commitment of Resources

Economic Analysis
- Direct Costs
- Capital Availability
- Local Economic Impacts

Considering Alternative Control Systems

The following comparison has been performed primarily to compare what a BART analysis and determination might look like if one were to be formally performed for the Centralia Plant. To that end, the guidance prepared by EPA on determining BART has been used as the vehicle to compare the emission alternatives. The following analyses are based on information submitted by the Centralia Plant for the 1997 RACT review for the Centralia Plant, and other publicly available information. The RACT Submittal documents (Refs. 7 and 29) were developed by the Centralia Plant owners.

A secondary use of this comparison is to compare a BART analysis to the negotiated emissions limitations that resulted from the 1996 collaborative decision making (CDM) process.

As a result of the following analyses it is likely that a BART level of technology would be met by the CDM/RACT emission limits of:

	Annual Average, lb/MBtu	**Annual Total, tons per year**	**Other**
SO_2	--	10,000	Not over 250 ppm, 1 hr average
NO_x	0.30	--	--
Particulate Matter	--	--	0.010 gr/dscf and not over 20% opacity

8.1.1 Plant History and Setting

Construction of the Centralia Plant was completed in 1971 and 1972, for Units #1 and #2, respectively. The construction of this facility predates the promulgation of any federal New Source Performance Standard (NSPS). When designed and originally put into operation, the plant was considered to have a design life of 30 years. Based on operation of other coal fired power plants, the Plant owners anticipate this plant will be capable of operation to at least 2025.

Over the last 20 years, SO_2 emissions from the Centralia Plant have varied directly with the portion of the Plant capacity utilized annually (capacity factor) and the sulfur content of the coal burned.

As displayed in Table 8.1-1, the consumption of coal has remained relatively constant since 1988, with an annual coal consumption of about 5.5 million tons per year. The CMC mine produces about 4.8 to 5.3 million tons of coal per year with the remaining coal supply obtained from external coal sources. The use of external coal tends to increase when energy output of the Plant is higher as measured by the capacity factor. This appears to be, in part, caused by the need to blend higher Btu coal when the plant exceeds the capacity of the Centralia Mine to produce coal, or to blend lower sulfur coal.

Table 8.1-1

SO_2 Emissions Compared to Capacity Factor

Year	SO_2 Emissions (Tons/year)	Average SO_2 Emissions (lb/MBtu)	Annual Coal Burned (Tons/yr)	Capacity factor at 1,340 MW (Percent)
1988	67,270	1.48	5,560,800	73.7%
1989	61,755	1.39	5,513,900	72.6%
1990	58,297	1.51	4,852,200	62.7%
1991	59,450	1.43	5,173,400	67.2%
1992	69,488	1.39	6,122,100	81.6%
1993	63,960	1.39	5,606,600	74.8%
1994	67,435	1.35	5,979,412	83.3%
1995	52,941	1.72	3,831,919	49.9%
1996	78,272	1.59	5,487,882	68.5%

* Based on actual electrical generation data for plant as provided in PacifiCorp comment letter dated October 29, 1997. Prior to 1992, the unit Maximum Dependable Capability was rated below 670 MW per unit.
100% Capacity Factor Btu Consumed = 122,901,048 MBtu/year.
100% Capacity Factor Coal consumption based on average coal Btu content of 7,884 Btu/lb = 7,794,333 Tons/yr of coal.

The Plant was originally equipped with one set of ESPs (Koppers). This single set of ESPs proved inadequate for the Plant to meet its particulate limitation. After a period of trying other options, a second set of ESPs, in series with the Koppers, were constructed (Lodge Cottrell). This additional set of ESPs allowed the plant to more than meet the particulate matter limit of 0.06 gr/dscf guaranteed by Koppers and permitted by SWAPCA. The Washington State standard for particulate matter is 0.10 gr/dscf. The Centralia Plant has shown through recent and historical annual emissions testing that it is fully capable of emitting particulate matter at levels of 0.005 gr/dscf. At current emission rates and ESP removal efficiency, the facility appears to be capable of meeting and exceeding the EPA, coal fired electric power plant New Source Performance Standard (NSPS) (40 CFR 60.40a et seq.) emission limitation for particulate matter of 0.03 lb/MBtu (~0.018 gr/dscf).

The Centralia Plant was constructed and permitted before feasible emission controls for NO_x were available. However, in recent years, the boilers have been operated in such a manner to minimize NO_x emissions. The facility appears to be capable of meeting the EPA, coal fired electric power plant New Source Performance Standard (NSPS) emission limitation for NO_x of 0.50 lb/MBtu. Evidence of this capability is the decision by the Centralia Plant to enter the Acid Rain Program NO_x Early Election program requiring it to meet a NO_x limit of 0.45 lb/MBtu.

During the early 1980s, the Plant emitted about 79,700 tons/yr of SO_2 (about 2.0 lb SO_2/MBtu at a 65% annual capacity factor) (Ref. 19). This was primarily due to the sulfur content of the coal mined at that time. More recently, the sulfur content of the coal declined. However, tests of coal seams that have not yet been excavated, indicate that the sulfur content of the coal will return to levels reached in the early 1980s. The uncontrolled SO_2 emissions are estimated to average about 88,681 tons/yr over the period 2002 through 2007, assuming that the annual plant capacity factor does not exceed the anticipated 70%. If the annual plant capacity factor were to rise to 84%, the uncontrolled annual emissions, based on the projected coal sulfur content, could rise to over 106,416 tons/yr.

Since the early 1980s, the Centralia Plant and Centralia Mine have developed procedures to store and blend coal from different coal seams in the Centralia Mine to meet an upper target of 0.95% sulfur (about 2.3 to 2.4 lb SO_2/MBtu) in the coal delivered by the Mine to the Plant. Annual average stack emissions in the early 1990s were about 1.3 lb SO_2/MBtu. In addition, the Centralia Plant has contracted for small quantities of low sulfur Powder River Basin coal to blend with Centralia coal, as needed, for control of SO_2 emissions and to maintain heat rate. Coal blending has been the only SO_2 control measure that the plant has used to achieve compliance with the current SWAPCA and State SO_2 emissions limitation of an average of less than 1000 ppm over a 60 minute period.

8.1.2 Particulate Matter Control Technology Evaluation

8.1.2.1 PM NSPS Considerations

The EPA BART guidance (Ref. 33) begins with a test of whether meeting an applicable NSPS will result in a noticeable improvement in visibility impacts. This test provides an easy determination of whether imposition of those controls will be environmentally beneficial and cost effective.

The NSPS limitations for coal fired electric generating facilities were developed in the late 1970s and withstood an industry appeal that was completed in 1980. Particulate emission standards in the applicable NSPS are based on the use of electrostatic precipitators (ESPs). The background document and the preamble to the 1979 final regulation (NSPS) (44 FR 33580-33624, No. 113, dated June 11, 1979) noted that, while baghouses had not been used for particulate control on combustion sources, baghouses were starting to be used as best available control technology (BACT) and lowest achievable emission rate (LAER) technology on new coal fired electric generating facilities. EPA anticipated that their use would become more common in the future.

The Centralia Plant has installed 2 sets of ESPs, in series, to control its particulate matter emissions. The resulting emissions are considered extremely low and provide approximately 99.6% removal efficiency.

The emissions data supplied in the RACT submittals (Ref. 7 and 29), have been reanalyzed to determine whether the facility could comply with the NSPS emission limits for particulate matter. The particulate matter emissions data reported to SWAPCA by the Centralia Plant is the total of filterable particulate (front half) and condensible particulate (back half). The NSPS is written in terms of filterable particulate (EPA Method 5). Relevant plant data must be extracted for comparison with the NSPS. Source tests performed since 1989 indicate that the condensible particulate matter emissions have averaged about 86% and 65% of the total particulate matter for Units #1 and #2, respectively. The Centralia Plant reports source test results in units of gr/dscf and lb/hr. The NSPS emission limits are in units of lb/MBtu. Under the NSPS particulate matter emission limits, the Centralia Plant could emit up to 1290 tons/yr (at 70% capacity factor) of filterable particulate. Based on the emissions reporting in the RACT submittals (Ref. 7 and 29), the Centralia Plant emitted 665 tons/yr in 1996, 513 tons/yr in 1990, and an average of 551 tons/yr of filterable PM over the time period 1989 to 1996, or approximately 50% of the NSPS limit.

8.1.2.2 PM Conclusion

The Centralia Plant currently uses particulate matter control technology that results in emissions below the applicable NSPS emission limits. It is not reasonable to expect that additional controls for PM, emissions of which are currently below the NSPS limitation, will result in perceptible improvement in visibility. Further PM emission controls will not affect secondary particulate matter, much of it $PM_{2.5}$, formed in the atmosphere from gaseous emissions of SO_2 and NO_x. All that is needed is a lower cap than the state standard or current SWAPCA limit to insure no regression in impacts occurs. This has been documented in earlier sections in this Technical Support Document. Therefore, the remaining elements of the BART guidance criteria do not need to be evaluated for particulate matter.

8.1.3 Nitrogen Oxides Control Technology Evaluation

8.1.3.1 NO_x NSPS Considerations

The EPA BART guidance begins with a test of whether meeting an applicable NSPS will result in a perceptible improvement in visibility. This test provides an easy determination of whether imposition of BART emission limits will be environmentally beneficial and cost effective.

The NSPS emission limitations for coal fired electric generating facilities were developed in the late 1970s and were able to withstand an industry appeal that was completed in 1980. NO_x emission limitations were based on the use of good combustion operation of the boilers and through the use of combustion air modifications that minimize emissions. The preamble to the 1979 final regulation (NSPS) (44 FR 33580-33624, No. 113, dated June 11, 1979) noted that, while at that time, add-on emission control systems, notably selective catalytic reduction systems, were available, but that there was inadequate experience with the technology on full size utility boilers.

The Centralia Plant has opted into the Early Election NO_x compliance plan under the EPA Acid Rain Phase II Program. To meet the requirements of this plan, the Centralia Plant must emit no more than 0.45 lb/MBtu on an annual average. The NSPS limitation is 0.50 lb/MBtu, 30-day average. To compare the different limits, the heat input and emission rates for 1996 were analyzed to determine if the Plant could meet the NSPS emission limitation. The results of that evaluation summarized in Table 8.1-2 indicate that the Centralia Plant could not meet the NSPS limit in 1996 because the maximum 30 day average for 1996 was 0.58 for Unit #1 and 0.51 for Unit #2. The use of combustion system modifications would be necessary based on 1996 emission rates to meet the NSPS limit, as shown in the Table 8.1-2 columns labeled NO_x Emissions @ 15% Reduction. Such a reduction in NOx emission rate from the 1996 levels results in maximum 30 day averages of 0.50 and 0.43 lb/MBtu for Units #1 and #2, respectively. The emission reduction used in Table 8.1-2 is based on a reduction from the Early Election level of 0.45 lb/MBtu to the CDM Target Solution level of 0.38 lb/MBtu, or 15%. This reduction percentage is roughly equivalent to the best expected performance of a low NO_x Level I control system applied to boilers like those at the Centralia Plant.

Table 8.1-2

Centralia Plant NO_x Emissions Summary
Effect of Application of NSPS Emission Limits
Unit 1, 1996 Operating Characteristics

	NO_x Emissions (lb/MBtu)	NO_x Emissions @15% Reduction (lb/MBtu)
Annual Average 1996	0.425	0.360

	NO_x Emissions (ton/yr)	NO_x Emissions @ 15% Reduction (ton/yr)
Annual Total 1996	9,080	7,718

30 Day Average Statistics

Maximum	0.582	0.495
Minimum	0.340	0.289
Median	0.408	0.347
Average	0.427	0.363
1 Std. Deviation	0.056	0.048
Average + 2 Std. Dev.	0.539	0.458

Unit 2, 1996 Operating Characteristics

	NO_x Emissions (lb/MBtu)	NO_x Emissions @15% Reduction (lb/MBtu)
Annual Average, 1996	0.440	0.373

	NO_x Emissions (ton/yr)	NO_x Emissions @15% Reduction (ton/yr)
Annual Total, 1996	9,485	8,062

30 Day Average Statistics

Maximum	0.511	0.434
Minimum	0.393	0.334
Median	0.438	0.372
Average	0.442	0.376
Std Deviation	0.031	0.027
Average + 2 Std. Dev.	0.504	0.429

15% reduction for NO_x means the NO_x formation potential of the combustion system is reduced by 15% through the use of combustion system modifications which assumes the upper end of the performance range for low NO_x Level I controls.

8.1.3.2 NO_x Control Technology Options

In evaluating the emission control opportunities for NO_x at the Centralia Plant, the 1997 RACT submittal (Ref. 29) evaluated a total of 37 different processes. Many of these processes are currently in the developmental stage or have not been demonstrated at a scale that would allow confidence in applying the technology at a facility the size of the Centralia Plant.

The 37 control options that were considered, break down into four basic technology groups.
Combustion modifications
NO_x only post combustion controls
Combined NO_x/SO_x post combustion controls
Repowering

The listing of all 37 control technologies considered is attached to the end of this review.

Many of the combined NO_x/SO_x control systems are proprietary and have been used only on small facilities or only demonstrated in pilot testing. Some of the combustion modification options have similar limited operational history.

Of the 37 options that were considered, 9 options were evaluated in more detail. These were:
(1) Boiler tuning
(2) Fuel and air tip replacement
(3) Close coupled over fire air (CCOFA or LNCFS Level 1)
(4) Separated over fire air (SOFA or LNCFS Level 2)
(5) CCOFA and SOFA (LNCFS Level 3)
(6) Natural gas reburning
(7) Selective noncatalytic reduction (SNCR)
(8) Selective catalytic reduction (SCR)
(9) A hybrid system of SNCR plus SCR

Boiler tuning

This option involves making a number of adjustments to the boiler operating parameters that affect the generation of NO_x in the boiler fire box. Changes that can be made to affect NO_x generation include excess air levels, secondary air biasing, fuel/auxiliary air damper adjustments, burner tilt, coal mills in service, fuel flow biasing, and changes to primary air flows. The use of these adjustments provide unpredictable levels of improvement in NO_x generation rates. The range of improvement that has occurred at different facilities is 5 to 40%, while typical improvements are in the 5 to 15% range.

Fuel and air tip replacement

This option modifies the location of the start of the flame zone relative to the end of the injector tip. This technology results in low and unpredictable emissions reductions.

Low NO_x Combustion Firing Systems

Low NO_x Combustion Firing Systems (LNCFS) in general are the technology of choice to reduce NO_x emissions from coal fired electric power boilers and most especially the retrofit technology most common for tangentially fired boilers like Centralia Plant. All of these options utilize the concept of combustion staging. This means that initial (first stage) combustion occurs in a fuel rich/oxygen poor condition, then additional air (oxygen) is added to the first stage combustion products to complete the combustion process. This combustion modification results in lower NO_x generation rates, but tends to increase CO emissions. Because some of the combustion occurs in an oxygen poor combustion condition, boiler walls and water tubes experience increased amounts of slag formation over `normal' combustion conditions. The next 3 options are all based on these combustion modification concepts.

Close coupled over fire air (CCOFA or LNCFS Level 1)

This modification incorporates the lowest amount of staging. This is due to this option requiring the smallest amount of modification to the existing boiler system. The primary changes are in the replacement of the fuel nozzles with >Concentric Firing System= nozzles and the top row of burners devoted to solely delivering air to the fire box. At Centralia Plant, this system is expected to provide a 9% reduction in NO_x emissions.

Separated over fire air (SOFA or LNCFS Level 2)

This modification provides for more combustion staging than does CCOFA. The same modified burner nozzles are used, but instead of removing the top row of burners from service, a new secondary air delivery system is constructed to supply secondary (over fire) air to the fire box. At Centralia Plant, this system is expected to provide a 27% reduction in NO_x emissions.

CCOFA and SOFA (LNCFS Level 3)

This modification provides the greatest amount of combustion staging. The equipment and burner modifications for both CCOFA and SOFA are included in this option. The NO_x generation rate is the lowest of these options, and because of how the SOFA equipment is designed and operated, the CO emissions and the amount of unburned carbon generated are lower than the other options. At Centralia Plant, this system is expected to provide a 36% reduction in NO_x emissions.

Natural gas reburning

This option is a variation on the LNCFS systems where a portion of the energy requirements of the boiler are introduced in the form of natural gas into the secondary combustion zone of the fire box along with the over fire air and some recirculated flue gas. This system typically provides for 40 to 50% reduction in NO_x emissions.

Selective Noncatalytic reduction (SNCR)

In this add on control technology, ammonia or urea is injected into the flue gas where the temperature of the flue gas is about 1800 to 1900EF. At this temperature, NO_x and the ammonia or urea react to form nitrogen gas and water. There is a great deal of temperature sensitivity in this reaction and since the urea or ammonia are often injected as aqueous solutions, there is an energy penalty on the overall boiler efficiency from vaporizing the water. Relatively small concentrations of ammonia result from the use of this NO_x control. This system typically provides for 65% reduction in NO_x emissions.

Selective catalytic reduction (SCR)

In this add on control technology, ammonia or urea is injected into the flue gas where the temperature of the flue gas is between 575 and 800EF. At this temperature and in the presence of an appropriate catalyst, NO_x and the ammonia or urea react to form nitrogen gas (N_2) and water. The presence of SO_2 in the flue gas can lead to the fouling of the catalyst with ammonium sulfate. This can significantly reduce the catalyst's useful life. In a natural gas fired unit, the catalyst lifetime can be in excess of 5 years. When burning a fuel with 1% or more sulfur content, this lifetime can be reduced to less than 1 year. This system results in a consistent, small emission of ammonia, and when inadequate SO_2 controls have been employed can result in a highly visible plume of ammonium sulfate. This system typically provides for up to 90% reduction in NO_x emissions.

A hybrid system of SNCR plus SCR

In this control option, a portion of the NO_x removal is accomplished through the use of SNCR. The remaining removal is accomplished through the use of SCR. Most of the NO_x reduction is accomplished with the SNCR system, but close control of the process is not required. The SCR system is then used to >polish= the emissions from the SNCR system, resulting in reduced ammonia emissions. This system typically provides for up to 90% reduction in NO_x emissions.

Cost of Controls

The following table indicates the estimated costs of emission controls and the anticipated emission control cost effectiveness.

Table 8.1-3

Cost Effectiveness of NO_x Control Options

Control Technology	Emission Rate, Annual Avg. (lb/MBtu)	Capital Costs ($)	Annual Costs ($)	% Removal	Controlled Emission Rate (lb/MBtu)	Controlled Emission Rate (ton/yr)	Annual Cost Effectiveness ($/ton)	PTE-Based Annual Cost Effectiveness ($/ton)
Boiler tuning	0.40 - 0.44	536,000	52,775	5%	0.42	18,066	$61	$6
Fuel and air tip replacement	0.40 - 0.44	4,556,000	448,584	5%	0.42	18,066	$521	$55
CCOFA	0.38 - 0.42	6,030,000	810,639	9%	0.40	17,206	$471	$90
SOFA	0.30 - 0.34	11,390,000	1,138,385	27%	0.32	13,765	$259	$107
CCOFA + SOFA	0.26 - 0.30	14,070,000	1,602,258	36%	0.28	12,044	$233	$113
SNCR	0.29 - 0.33	9,648,000	11,915,370	30%	0.31	13,335	$2,131	$923
SCR	0.10 - 0.15	94,632,700	26,991,205	70%	0.13	5,592	$2,024	$1,307
Hybrid SCR/SNCR	0.24 - 0.28	20,904,000	15,155,181	41%	0.26	11,184	$1,957	$1,007
Natural gas reburning	0.23 - 0.27	20,100,000	15,970,757	43%	0.25	10,754	$1,954	$1,031

Annual costs include anticipated penalty for lost ash sales when using SCR of SNCR

Uncontrolled emissions rate, 18,927 tons/yr

Uncontrolled emissions rate, 0.44 lb/MBtu

"PTE" = Potential to Emit, the maximum expected emissions without controls; cost effectiveness includes effect of larger potential reduction in emissions.

8.1.3.3 Visibility Impairment Improvements Possible

In 1990, the National Park Service conducted an intensive ambient monitoring program to determine the nature and extent of air pollution impacts on national parks and wilderness areas in Western Washington. The results of this investigation were published in 1994 in a study referred to as PREVENT (Ref. 21). This study indicated that NO_x emissions from the Centralia Plant result in an insignificant impact to the air, water, and terrestrial resources of Mount Rainier National Park. Subsequent analyses of the data collected during that study indicated that nitrates emitted by the Centralia Plant caused less than 2% of the uniform haze visibility impairment at Mount Rainier.

The use of ammonia as part of NO_x emission control technology has the potential for causing emissions of ammonia to the atmosphere. This ammonia would react with sulfur oxides and nitrogen oxides to form a highly visible fine particulate of ammonium sulfate and ammonium nitrate. The quantity of these chemicals produced will depend on the level of control of the SCR or SNCR process used to control NO_x emissions. High levels of control and long periods of stable operation will result in a high degree of NO_x and ammonia control while unstable operation and NO_x emission rates will lead to the highest levels of ammonia emissions.

The degree of visibility improvement from the application of NO_x emission controls at Centralia Plant will be insignificant.

8.1.3.4 Water Quality/Quantity Aspects of the NO_x Control Options

There is no anticipated adverse effects on water quantity or water quality due to the use of any of the NO_x emission control options evaluated. The options using SCR or SNCR will result in a slight reduction of waste water discharged to Big Hanaford Creek. The quantity of effluent that is reduced has not been quantified.

There is a possibility that the use of SCR or SNCR will add ammonia to the scrubbing liquor used in a wet scrubbing system to control SO_2 emissions. The wastewater discharged from this scrubbing system could result in an increase in the ammonia concentration in the discharge of wastewater to Big Hanaford Creek. This would necessitate a modification of the Plant=s waste water discharge permit.

Atmospheric deposition of nitrates originating from the Centralia plant can result in a decrease in the pH of lakes in the trajectory of the plant's plume. This effect is small but over a large number of years, might accumulate to be a problem. At the present time, the most impacted lake in Washington appears to be Summit Lake in the Clearwater Wilderness, northeast of Mount Rainier. This lake appears to have a limited buffering capacity due to the geology of its watershed. Based on the information in the USFS report (Ref. 22), Forest Service researchers indicate that spring and summer rainfall plus a localized wind flow from urban Puget Sound may be the primary source of acidic deposition in the Summit Lake watershed. Analyses also indicate that the primary component of the acidic deposition is sulfates.

8.1.3.5 Solid and Hazardous Waste Impacts of NO_x Control Options

Changes to the combustion process are not anticipated to have any impact on the quantity or quality of solid wastes and ashes produced by this facility. The use of SCR or SNCR have a possibility of contaminating the fly ash with moderate levels of ammonia. This contamination would prevent or significantly reduce the potential for continued sale of the fly ash because of odor concerns. Any unsold fly ash would need to be disposed of either as backfill in the Centralia Mine or in a special purpose landfill. See the SO_2 controls section for a more detailed discussion of landfill options and impacts.

The contamination of the fly ash with ammonia also has the potential of causing it to be designated as a dangerous waste under Washington State regulations. Consultants for the Centralia Plant have made preliminary estimates of the most likely ammonia concentrations in the ash. These estimates indicate that the ammonia concentration will most likely be below the dangerous waste designation threshold.

8.1.3.6 Energy Impacts of the NO_x Control Options

Energy Consumption

The use of combustion controls for NO_x emission control have the tendency to increase CO emissions. This means that the energy in the fuel is not being completely recovered. The effects of this minor amount of incomplete combustion is an increase in the fuel consumption to produce a given amount of electricity. The effect of this increase in coal consumption is expected to be very minor.

The use of natural gas reburning will decrease the usage of coal and increase the usage of natural gas. The quantity of natural gas necessary for this option is currently available in the Northwest Pipeline Company pipeline near the plant. This option uses significantly less natural gas than the fuel conversion option discussed in the SO_2 control section. The use of natural gas reburning is anticipated to decrease the uncontrolled SO_2 emissions by about 10% from the uncontrolled rate.

Impact on Scarce Fuels

The operation of the evaluated NO_x control options do not have a direct impact on the availability of scarce fuels due to their use at the Centralia Plant. Due to the consumption of natural gas pipeline capacity to provide natural gas for the natural gas reburning option, there will be reduced pipeline capacity available for other users.

The use of SCR or SNCR will cause the consumption of natural gas through its use in making ammonia and urea.

Energy Consumption Impact of NO_x Control Options

None of the NO_x control options affect the gross energy consumption of the Centralia Plant. The options that involve chemical addition (SCR and SNCR) do affect the total net electricity produced. The losses of net electrical output come from the added pressure drop on the flue gas flow with an SCR system requiring an ID fan upgrade, the effect of water injected into the fire box and requirements for compressed air when using the SNCR process, and by on-site electrical consumption by pumps used to inject the ammonia or urea into the flue gas for both types of systems.

Local Economic Impacts

The local economic impacts of the addition of ammonia controls to the Centralia plant are considered to be very minor because coal mine production and employment will not be affected. The use of natural gas reburning as a NO_x control measure may result in the reduction of coal production by 25%. Compared to the closure of the Centralia Mine that could occur from the application of some of the SO_2 control measures, this possible reduction in coal production will have a lesser impact, but still could be substantial.

Irreversible Natural Resource Commitments

The use of SCR or SNCR irrevocably consume natural gas to produce the urea or ammonia used to control the NO_x emissions from the Centralia Plant.

The use of natural gas in the reburning option and as a fuel to produce ammonia and urea consumes this fossil fuel. Currently Northwest Pipeline Company, the natural gas supplier to western Washington, purchases its gas supplies from Canada and production fields in the western Colorado/eastern Utah area, and northwestern New Mexico areas of the US. All of these areas have limited production lifetimes. As supplies in the current production areas decline, new production areas will have to be found and the cost of the gas from those new fields will cost commensurately more.

8.1.3.7 NO_x Conclusion

Based on the currently available visibility impairment analyses, the possible visibility improvement or reduction in potential visibility impairment that would result from the control of NO_x at the Centralia Plant is below the level of human perception. This is not to say that there are other air quality related impacts caused by the emission of NO_x from the Centralia Plant that can be reduced.

Reduction in the quantity of potential ozone formed during the summer and reduced acidic deposition and nutrient enrichment is a valuable result of NO_x emission controls. Reductions of NO_x emissions from the Centralia Plant will result in important benefits to the environment.

Based on the analyses performed, the application of Level III low NO_x combustion controls will achieve NO_x emission control for Centralia Plant consistent with BART. The application of this level of control with an annual average emission limit of 0.30 lb/MBtu represents the best balance of emissions reduction and cost at this facility.

A NO_x emission rate limit of 0.30 lb/MBtu, annual average, meets or exceeds the NSPS requirements for relevant coal-fired power plants. This level of emissions control appropriately balances the environmental costs and benefits of the NO_x control options evaluated for this review. The choice of control option is left as an evaluation of cost effectiveness and capital costs. As presented in Figure 8.1-1 below, the use of Level III combustion controls (CCOFA + SOFA) provides the most cost effective emissions reduction.

Figure 8.1-1

NOx Control Technologies

8.1.4 Sulfur Dioxide Technology Evaluation

8.1.4.1 SO_2 NSPS Considerations

The EPA BART guidance begins with a test of whether meeting an applicable NSPS will result in a perceptible improvement in visibility. This test provides an easy determination of whether imposition of those controls will be environmentally beneficial and cost effective.

The NSPS emission limitations for coal fired electric generating facilities were developed in the late 1970s and were able to withstand an industry appeal that was completed in 1980. SO_2 emission limitations were based on the use of lime or limestone wet scrubber systems. The preamble to the 1979 final NSPS regulation (44 FR 33580, No. 113, dated June 11, 1979) noted that while at the time of promulgation other SO_2 control systems were being developed, most notably dry scrubber systems, that appeared capable of meeting the proposed NSPS limitations. EPA also recognized that there were a number of considerations related to setting the emission limit for SO_2. One of those considerations was the need to make maximum use of locally available coals. Additionally, there was a concern with the inability of a plant to meet a low emission limit for compliance periods shorter than 30 day averages. Another consideration had to do with emissions reduction percentage. The EPA determined that for controlled emissions rates below 0.6 lb/MBtu, a lower emission reduction requirement is more appropriate than when using high sulfur coals which were given an emission limit of 1.2 lb/MBtu.

An NSPS emission rate limit of 0.6 lb/MBtu, 30 day average, corresponds to a required control system performance of 70% emission reduction. An emission reduction of 70% was applied to the Centralia Plant 1996 SO_2 emissions data to evaluate whether such reductions could generate a noticeable reduction to visibility impairment. A 70% reduction was also applied to present emissions to estimate whether the Centralia Plant could comply with a 10,000 ton per year annual limit and a 0.6 lb/MBtu, 30 day average limitation.

Based on the operating characteristics for 1996, as shown below, the 10,000 ton per year annual limit is much more restrictive than the 0.6 lb/MBtu, 30 day average limitation when evaluated over a calendar year.

	SO_2		
	Annual Average lb/MBtu	**Max. 30 day Average lb/MBtu**	**Annual Emissions tons/yr**
Unit 1	0.45	0.52	10,687
Unit 2	0.47	0.51	11,093
TOTAL	--	--	21,780
CDM Limits	--	--	10,000

8.1.4.2 SO_2 Control Technology Options

In evaluating the emission control opportunities for SO_2 at the Centralia Plant, the 1997 RACT Review compares a total of 74 different processes. Many of these processes are currently in the developmental stage or have not been demonstrated at a scale that would allow confidence in applying the technology at a facility the size of the Centralia Plant.

The 74 different control options that were looked at break down into 4 basic technology groups.

(1) Pre-combustion controls such as coal cleaning, and fuel switching.
(2) Combustion Zone controls such as limestone injection into the fire box.
(3) Repowering options such as conversion to fluidized bed, conversion to natural gas and coal gasification, combined cycle.
(4) Post combustion control processes:
  (a) Simultaneous SO_x/NO_x control measures such as ISCA, NOXSO, and other patented processes.
  (b) Regenerative processes based on sodium or magnesium.
  (c) Limestone or lime based processes.
  (d) Ammonia based process.

The following three pages is a complete listing of the 74 SO_2 emission control options that were evaluated.

Based on literature reviews and industry experience, the focus of this review was narrowed to the 6 different options (with up to 3 variations of each option) that have the best chance of meeting the 10,000 tons/yr SO_2 limit. Criteria for exclusion are the same as used in reducing the list of 74 to 7 options in the Centralia Plant RACT submittals (Refs. 7 and 29). Four additional options reflecting partial scrubbing were added to the 7 options evaluated by the Centralia Plant owners.

The options that are the focus of comparison consist of the following:

(1) All low sulfur external coal.
(2) Lime Spray dryer with Centralia Mining Company (CMC) coal and existing ESPs.
(3) Lime Spray dryer with CMC coal and new baghouse.
(4) Lime Spray dryer with external coal and existing ESPs.
(5) Ammonium sulfate forced oxidation (Ammonium Sulfate Forced Oxidation) scrubber with CMC coal.
(6) Limestone forced oxidation (LSFO) with CMC coal.
(7) Conversion of plant to natural gas.
(8) Use of Limestone Forced Oxidation to 90% removal, one unit.
(9) Use of Limestone Forced Oxidation to 50% removal both units.
(10) Use of Ammonium Sulfate Forced Oxidation to 90% removal, one unit.
(11) Use of Ammonium Sulfate Forced Oxidation to 50% removal both units.

SO_2 Control Technologies

Costs and removal rates for these controls have been estimated and are shown in Table 1 below. The costs for Ammonium Sulfate Forced Oxidation or Limestone Forced Oxidation at 50% emissions control were not estimated in the 1997 RACT Submittal (Ref. 29) because this RACT review focused on emissions controls that could meet the CDM Target Solution for SO_2 control. This BART evaluation is not restricted by this consideration and as such will look at levels of control that are less than the CDM Target Solution. In addition, this evaluation did not include options that were a combination of options that, by themselves, were marginally cost effective such that, by combing these options, they were not practical or cost effective, such as all off site coal and full scrubbing, combined.

Description of control options

There are 11 emission control technologies that are being considered in this analysis as being the most viable from an environment, energy, cost and practical standpoint.

Option 1: <u>All low sulfur external coal</u>

This emission control option consists of closing the Centralia Mine, adding a new railroad track to enable the plant to accept unit trains of coal from the Powder River Basin or overseas, and modifications to the boilers to accept the different coal. This option would have the most local employment, and probable solid waste impacts. The solid waste impacts result from the lack of the mine availability for ash disposal.

Option 2: <u>Lime Spray dryer with Centralia Mining Company (CMC) coal and existing ESPs</u>

In this emission control option, lime is mixed with water and sprayed into the hot flue gases either in existing ducts or in new reaction vessels. The atomized lime slurry contacts the SO_2 containing gases and reacts to form calcium sulfite while drying the slurry to dry particles that are removed with a particulate matter control device. Operating experience has shown that the use of the existing Lodge-Cottrell ESPs to control the particulate after a spray dryer result in about a 75% reduction in SO_2 emissions. This process generates relatively large quantities of unsalable solid waste that must be disposed of in the mine or at an on- or off-site landfill. This version of the spray dryer option continues the use of Centralia Mine coal.

Option 3: <u>Lime Spray dryer with CMC coal and new baghouse</u>

This control option is identical in concept as Option 2 with one change. The existing Lodge-Cottrell ESPs will be converted into bag houses. The use of bag houses will increase the SO_2 removal rate to about 90%. The increased removal rate comes about through increased contact time of the exhaust gases with unreacted lime which coats the bags in the baghouse. Solid waste disposal of the collected particulate will be the same as Option 2.

Option 4: <u>Lime Spray dryer with external coal and existing ESPs</u>

This control option is also identical to Option 2 with one change. In this case the Centralia Mine would be closed and all the coal will be imported from the Powder River Basin. Because of the initially lower SO_2 emissions resulting from the Powder River Basin coals compared to the Centralia coals, the 75% removal rate provided by the ESPs provides nearly the same level of emissions control as Option 3. The solid waste impacts are the same as for the other spray dryer options.

Option 5: Ammonium sulfate forced oxidation (ASFO) scrubber with CMC coal

This emission control option utilizes a wet scrubbing system that provides at least 90% SO_2 removal. The wet scrubbing system involves contacting the flue gases with an ammonia solution to generate a solution of ammonium sulfite and ammonium bisulfite. These chemicals are then oxidized through aeration to produce ammonium sulfate. The ammonium sulfate is removed from the spent scrubbing liquor in a crystalline form suitable for sale as fertilizer. The major draw back of this proposal is the handling and storage of anhydrous ammonia. Ammonia is known to be a toxic chemical and requires special handling and maintenance procedures. The need for discharging scrubber blowdown to the plant wastewater system may result in an ammonia limitation on the plant NPDES permit. There are no new solid waste impacts for this option.

Option 6: Limestone forced oxidation (LSFO) with CMC coal

This emission control option utilizes a wet scrubbing system that provides at least 90% SO_2 removal. The wet scrubbing system involves contacting the flue gases with a pulverized limestone in water slurry to generate a solution of calcium sulfite and calcium bisulfite. These chemicals are then be oxidized through aeration to produce gypsum (calcium sulfate). The gypsum is removed from the spent scrubbing liquor in crystalline form for sale to wallboard manufacturers in the Tacoma and Seattle areas. The major draw back of this proposal is the need to have a continuous water discharge from the system to keep chlorides low enough to allow the sale of gypsum for wallboard. The water discharge is to be routed to the existing wastewater treatment system. New solid waste could be generated from this process if the gypsum produced is not suitable for manufacturing wallboard.

Option 7: Conversion of plant to natural gas

This option involves the installation of a new natural gas pipeline to the Centralia Plant, closure of the CMC mine, and boiler modifications to make it suitable for natural gas combustion. The major drawback is that the main natural gas pipeline is utilized at nearly its maximum current capacity and the conversion of the Centralia Plant would require 25% of the current pipeline capacity be routed exclusively to the Plant. This option has much higher fuel costs than using coal and those fuel costs do not appear to be offset by the reduced boiler maintenance resulting from the use of natural gas.

Option 8: Use of Limestone Forced Oxidation to 90% removal, one unit

This option is identical to control Option 6 with one exception. The controls would be sized to treat the emissions from the equivalent of one boiler's flue gases. Thus at maximum Plant operating conditions, the control system would provide only about 55% removal of SO_2 emissions. At lower operational levels, a higher percentage of the Plant emissions would be treated. Solid waste and water impacts would be about half of those for Option 6. Gypsum resulting from the scrubber system would be sold.

Option 9: Use of Limestone Forced Oxidation to 50% removal both units

This option is identical to Option 6 except the scrubbing system installed for each boiler would be sized to provide for 50% removal of SO_2. A major difference from Option 8 is that all emissions would be subject to 50% SO_2 removal through its entire operating range. Solid waste and water impacts would be about half of those for Option 6. Gypsum produced by the scrubbing systems would be sold.

Option 10: Use of Ammonium Sulfate Forced Oxidation to 90% removal, one unit

This option is identical to control Option 5 with one exception. The controls would be sized to treat the emissions from the equivalent of one boiler=s flue gases. Thus, at maximum plant operation conditions, the unit would provide only about 55% removal of SO_2 emissions. At lower operational levels, a higher percentage of the Plant emissions would be treated. Solid waste and water impacts would be about half of those for Option 5. Ammonium sulfate resulting from the scrubber system would be sold.

Option 11: Use of Ammonium Sulfate Forced Oxidation to 50% removal both units

This option is identical to Option 5 except the scrubbing system installed for each boiler would be sized to provide for 50% removal of SO_2. A major difference from Option 10 is that all emissions would be subject to 50% SO_2 removal through its entire operating range. Solid waste and water impacts would be about half of those for Option 6. Ammonium sulfate produced by the scrubbing systems would be sold.

The capital cost scenario for the last 4 emission reduction options are based on the deferred cost analysis for the Limestone Forced Oxidation process by Sargent & Lundy and its LSFO Phase I retrofit project average cost per kW without the effect of spare absorber capacity as presented in the 1997 RACT Submittal, Appendix D (Ref. 29, App. D, p. II.12-II.15). For the 90% scrubbing, one unit options (Options 8 and 10), a ratio of 0.75 was applied to the cost estimates developed for the 90% emission reduction Ammonium Sulfate Forced Oxidation and Limestone Forced Oxidation options presented in the 1997 RACT Submittal (Ref. 29, p. 32 and 43). The 50% scrubbing, both units options (Options 9 and 11) were estimated by scaling up the Sargent & Lundy average project cost per kW without redundancy by the ratio of the Sargent & Lundy average unit size to the half capacity system at Centralia Plant (350 MW). This value of $245/kW was further adjusted for the 50% ASFO option by the ratio of the costs for 90% reduction ASFO to 90% reduction LSFO since the Sargent & Lundy estimates were all based on LSFO systems. Using this relationship to scale costs may result in capital cost figures that are only rough estimates for the Ammonium Sulfate Forced Oxidation control option. However, the cost estimates are close enough not to disadvantage or misrepresent an option. The Ammonium Sulfate Forced Oxidation and Limestone Forced Oxidation use essentially the same scrubbing equipment and similar solids separation processes. Both scrubbing processes produce a crystalline precipitate material that can be separated from the scrubbing liquor by conventional solids separation equipment.

Table 8.1-4

Cost of Controls

Costs\Option	1	2	3	4	5	6	7	8	9	10	11
Capital cost plus AFUDC and escalation to year 2000	$ 58,330,000	$ 172,823,000	$ 211,444,000	$ 200,902,000	$ 251,676,000	$ 236,628,000	$ 27,358,000	$ 177,471,365	$ 191,045,930	$ 188,757,835	$203,195,688
O&M costs, one year	$ 323,000	$ 9,916,000	$ 12,035,000	$ 5,275,000	$ (410,000)	$ 5,177,000	$ (3,247,000)	$ 3,106,200	$ 3,365,050	$ (225,500)	$ (205,000)
Incremental Property Taxes	$ 759,264	$ 2,249,559	$ -	$ -	$ -	$ -	$ -	$ 2,310,057	$ 2,486,750	$ 2,456,967	$ 2,644,897

Annual costs based on Capital Recovery Factor of 0.09846

Costs\Option	1	2	3	4	5	6	7	8	9	10	11
Levelized Annual O&M and Property Taxes*	$ 1,428,588	$ 16,058,538	$ 15,886,200	$ 6,963,000	$ (541,200)	$ 6,833,640	$ (4,286,040)	$ 7,149,459	$ 7,724,376	$ 2,945,536	$ 3,220,665
Levelized Incremental fuel c	$ -	$ -	$ -	$ -	$ -	$ -	$ 105,953,022	$ -	$ -	$ -	$ -
SO2 Allowance Benefit**	$ (1,251,000)	$(1,690,800)	$ (3,021,100)	$ (3,021,000)	$ (3,021,000)	$ (3,021,000)	$ (3,873,400)	$ 82,800	$ 526,200	$82,800	$526,200
Capital Recovery	$ 5,155,661	$ 15,275,281	$ 18,688,889	$ 17,757,064	$ 22,244,871	$ 20,914,775	$ 2,418,079	$ 15,686,081	$16,885,890	$ 16,683,653	$ 17,959,765
Total Annual cost	$ 5,333,279	$ 29,643,019	$ 31,554,089	$ 21,699,064	$ 18,682,671	$ 24,727,415	$ 100,211,661	$ 22,918,340	$ 25,136,466	$ 19,711,990	$ 21,706,630
Uncontrolled Emissions, tons/yr	26,568	88,681	88,681	26,568	88,681	88,681	344	88,681	88,681	88,681	88,681
Controlled Emissions, tons/yr	26,568	22,170	8,868	8,868	8,868	8,868	344	39,906	44,340	39,906	44,340
Controlled Emission Rate, lb/MBtu	0.62	0.52	0.21	0.21	0.21	0.21	0.008	0.93	1.03	0.93	1.03
Emissions reduced***	62,112	66,510	79,812	79,812	79,812	79,812	88,336	48,774	44,340	48,774	44,340
Annual Cost/ton reduced	$ 86	$ 446	$ 395	$ 272	$ 234	$ 310	$ 1,134	$ 470	$ 567	$ 404	$ 490

Data is based on Table II-3 of 1997 RACT Submittal.

* From Table II-4 of 1997 RACT Submittal. Levelizing O&M/Fuel Factor of 1.32, based on discount rate of 9.13% and escalation rate of 3.0%.

** Based on price of $100/$SO_2$ allowance and 39,078 allowances awarded to Centralia Plant.

*** For options 1, 4, and 7, reduction is from uncontrolled emission level of 88,681 tons/yr corresponding to use of CMC coal.

For options 8 to 11, both operating and capital costs for 50% scrubbing on each unit are more expensive than for 90% scrubbing on one unit.

8.1.4.3 Visibility Impairment Improvement Possible

In 1990, the National Park Service conducted an intensive ambient monitoring program to determine the nature and extent of air pollution impacts on national parks and wilderness areas on Western Washington. The results of this investigation were published in 1994 (Ref. 21). This study indicated that SO_2 emissions from the Centralia Plant affected the air, water, and terrestrial resources of Mount Rainier National Park. Subsequent analyses of fine particulate data collected during that study indicates that sulfate attributable to the Centralia Plant caused about 16% of the uniform haze visibility impairment at Mount Rainier. These additional evaluations also estimated that the reduction of Centralia Plant SO_2 emissions to 10,000 tons/yr would result in the plant contributing 2% of the uniform haze visibility impairment at Mount Rainier.

The National Park Service's Air Resources Division also used a meso-scale dispersion model to estimate the potential visibility and sulfate deposition impact resulting from the SO_2 emissions from the Centralia Plant. That report (Ref. 18) was finalized in September, 1996. The report evaluated the visibility impairment potential and deposition rate potential due to only the Centralia Plant's emissions at 23 locations in and near to Class I areas in Washington and northern Oregon. One important observation of the report was that due to Centralia Plant SO_2 emissions, a location in the Mt. Adams Wilderness was predicted to experience the maximum visibility impairment (6.2 deciviews) of the 23 locations evaluated in the model. The pertinent visibility impact information from that report is presented below.

Emissions (tons/yr)	% Control	Potentially Impacted Days at All Modeled Sites
94,526	0%	53
69,414	0%	36
34,707	50%	13
20,824	70%	4
13,882	80%	2
7,000	90%	0

The NPS report (Ref. 18) evaluated the 1994 reported emission rate of 69,414 tons/yr to estimate the effects of the uncontrolled emissions on potential visibility and deposition. The lower emission rates were estimated based on adding controls to the 1994 emission rate. The 94,526 tons/yr emission rate and estimated visibility impact was provided by the National Park Service (Ref. 79).

The modeling analyses discussed in the report also estimated the sulfate deposition rates that would result from the Centralia Plant at the same 23 locations. The predicted Centralia Plant deposition rates do not exceed the NPS or USFS guidelines of 20 milliequivalents per square meter per year (about 3 kg/ha/yr as S or 9 kg SO_4/ha/yr) for protection of sensitive lakes and streams. Protection of sensitive receptors from acidic deposition is an air quality related value.

The following table provides estimates of the degree of visibility improvement possible by using the listed control options, assuming the validity of the underlying studies:

Table 8.1-5

Control Options Compared to Potential Days of Visibility Improvement and Annual Costs*

Option #	SO_2 Emissions	# Days With Deciview Change >1	Days of Visibility Improved**	Total Annual Cost	Cost/Days Improved
--	88,681	47			
--	*69,414	36			
11	44,340	21	26	$ 21,706,630	$ 834,870
9	44,340	21	26	$ 25,136,466	$ 966,787
10	39,906	17	30	$ 19,711,990	$ 657,066
8	39,906	17	30	$ 22,918,340	$ 763,945
1	26,568	9	38	$ 5,333,279	$ 140,349
2	22,170	6	41	$ 29,643,019	$ 723,000
5	8,868	1	46	$ 18,682,671	$ 406,145
4	8,868	1	46	$ 21,699,064	$ 471,719
6	8,868	1	46	$ 24,727,415	$ 537,552
3	8,868	1	46	$ 31,554,089	$ 685,958
7	344	0	47	$100,211,661	$ 2,132,163

* Days of visibility impairment, defined as deciview change > 1, and 69,414 tons/yr are from Vimont, NPS, Ref. 18.
** From projected emission rate of 88,681 tons/yr and extrapolated potential visibility impairment.

As illustrated in Table 8.1-5 above, most of the options provide a significant visibility improvement from both the 1994 emissions level of 69,414 tons/yr and from the much higher, 1999 projection of uncontrolled SO_2 emissions of 88,681 tons/yr. As an additional screening measure, it is assumed that any emissions control option that provides for less than 10 days per year of potential visibility impairment is considered to be sufficient. This provides at least a 72% improvement over Vimont's estimated 1994 visibility impairment and at least a 79% improvement over the extrapolated visibility impairment at the projected emissions level of 88,681 tons/yr. This is a lower level of visibility improvement potential than was finally required for the Navajo Generating Station which was impacting visibility in Grand Canyon National Park.

Visibility impacts were evaluated in accordance with the EPA guideline which indicated that the application of 70% emission reduction, the NSPS level of emissions control (represented by Option 1 above), would provide a reduction in the number of days of visibility impairment.

8.1.4.4 Water Quality/Quantity Aspects of the SO_2 Control Options

Approximately 50% of the Centralia Plant's current wastewater discharges is made up of treated stormwater. The remainder of the discharges are made up of cooling tower blowdown, bottom ash collection water and treated sewage and process drain flows. The majority of the current annual effluent flows from this facility are stormwater flows. These flows along with the other process flows are routed to wastewater storage and treatment lagoons prior to being discharged to Big Hanaford Creek. During the summer when the creek is at its lowest flow, there is no plant wastewater discharged to Big Hanaford Creek. A summary of the wastewater discharge impacts is provided in Table 8.1-6.

The largest amount of water diverted from the wastewater discharge system is evaporated in the treatment process and is emitted from the stack as water vapor. A minor amount of water is incorporated in the gypsum or ammonium sulfate produced by the control systems.

The Limestone Forced Oxidation process will require a continuous discharge stream of scrubber liquor in order to produce wallboard quality gypsum. The volume of this flow is estimated to be 73 gpm. In order to operate the Limestone Forced Oxidation and Ammonium Sulfate Forced Oxidation processes, 1567 gpm of wastewater will be diverted from the wastewater treatment ponds resulting in a decrease in the annual effluent flow to the Creek of about 86%. The use of lime spray dryer is estimated to reduce annual wastewater flow by about 63%.

The diversion of water from Big Hanaford Creek is not anticipated to adversely interfere with the water rights of any downstream users of Big Hanaford Creek, the Skookumchuck River or the Chehalis River.

Atmospheric deposition of sulfates originating from Centralia Plant can result in a decrease in the pH of lakes in the trajectory of the Centralia Plant's plume. The annual contribution of acidic chemicals by the Plant's emissions is small but over a large number of years, the cumulative effect can become a problem. At the present time, the most severely impacted lake in Washington appears to be Summit Lake in the Clearwater Wilderness, northwest of Mount Rainier. This lake appears to have a limited buffering capacity due to the geology of its watershed. Based on the information in the USFS report "Lake and Snow Chemistry of Summit Lake, WA" (Ref. 22). The Forest Service researchers indicate that spring and summer rainfall plus a localized wind flow from urban Puget Sound may be the primary source of acidic deposition in the Summit Lake watershed.

The National Park Service (NPS) studies of the emissions from the Centralia Plant indicate that the Centralia Plant's emissions contribute 0.85 kg/ha/yr at Eunice Lake, 0.84 kg/ha/yr at Lake Allen, and 1.2 kg/ha/yr at Tahoma Woods, to the total wet and dry deposition of acidic materials at those locations. For these high mountain lakes, this equates to about 30% of the total sulfur loading that can be sustained. (Ref. 21)

Simple dispersion modeling work done in 1985 and 1986 for the State Legislature on acid deposition policy issues (Ref. 19) indicated that a 90% reduction from the early 1980s emission levels of SO_2 from the Centralia Plant would result in a reduction in total wet sulfate deposition rate of about 30%. This is similar to the results predicted in the Vimont report and found in the PREVENT study (Ref. 21).

Table 8.1-6

Wastewater Discharge Impacts

SO_2 Control Option		Wastewater Discharge Impacts*
1	All External Coal	No change from current situation.
2	Lime Spray Dryer/ESP - CMC Coal	Dry scrubber consumes wastewater, NPDES discharge quantity reduced by 63%.
3	Lime Spray Dryer/Baghouse - CMC Coal	Dry scrubber consumes wastewater, NPDES discharge quantity reduced by 63%.
4	Lime Spray Dryer/ESP - all External Coal	Dry scrubber consumes wastewater, NPDES discharge quantity reduced by 63%.
5	Ammonia Scrubbing Forced oxidation - CMC coal	Wet scrubber consumes wastewater, NPDES discharge quantity reduced by 86%. Leaks from ammonia storage and unreacted ammonia in wet scrubber blowdown may affect wastewater.
6	Limestone Scrubbing Forced oxidation - CMC coal	Wet scrubber consumes wastewater, NPDES discharge quantity reduced by 86%. Chloride content of wet scrubber blowdown may affect wastewater.
7	Natural Gas	Water quality improved due to reduced stormwater runoff from coal and ash piles. NPDES discharge quantities reduced by 21%.
8	Limestone Forced Oxidation, 90% removal for one unit	Wet scrubber consumes wastewater, NPDES discharge quantity reduced by 43%. Chloride content of wet scrubber blowdown may affect wastewater.
9	Limestone Forced Oxidation, 50% removal each unit	Wet scrubber consumes wastewater, NPDES discharge quantity reduced by 43%. Chloride content of wet scrubber blowdown may affect wastewater.
10	Ammonium Sulfate Forced Oxidation, 90% removal for one unit	Wet scrubber consumes wastewater, NPDES discharge quantity reduced by 43%. Leaks from ammonia storage and unreacted ammonia in wet scrubber blowdown may affect wastewater.
11	Ammonium Sulfate Forced Oxidation, 50% removal each unit	Wet scrubber consumes wastewater, NPDES discharge quantity reduced by 43%. Leaks from ammonia storage and unreacted ammonia in wet scrubber blowdown may affect wastewater.

* Impacts are from 1994 RACT Submittal, Page 68, Ref. 7.

8.1.4.5 Solid and Hazardous Waste Impacts of SO_2 Control Options

The various control options evaluated will have a number of solid and hazardous waste impacts. Use of lime spray dryers for SO_2 control, coupled with closure of the CMC mine and use of imported coal is the option that would create the most adverse impacts. In this situation, all of the ash generated at the Centralia Plant along with the spray dryer fly ash would have to be disposed of in a specially designed and lined landfill. During emissions control system process upsets when using the ammonia or limestone control options, solid or potentially dangerous waste will be generated that must be properly disposed of. The following table indicates the types of impacts that result from the use of the various control technologies.

Table 8.1-7

Solid and Hazardous Waste Disposal Impacts

SO_2 Control Option		Solid and Hazardous Waste Disposal Impacts
1	All External Coal	Due to closure of the mine, land will be needed to establish an ash landfill for bottom and fly ash that cannot be sold. Ash is not anticipated to be hazardous.
2	Lime Spray Dryer/ESP - CMC Coal	Total ash volume increases due to injection of lime for SO_2 control. Fly ash volumes from second bank of ESPs will increase and will not be salable. Additional ash disposal in mine will occur. Ash is not anticipated to be hazardous.
3	Lime Spray Dryer/Baghouse - CMC Coal	Total ash volume increases due to injection of lime for SO_2 control. Fly ash volumes from new baghouse will not be salable. Additional ash disposal in mine will occur. Ash is not anticipated to be hazardous.
4	Lime Spray Dryer/ESP - all External Coal	Bottom and fly ash volume decreases with external coal, but additional waste created due to injection of lime for SO_2 control. Fly ash volumes from second bank of ESPs will not be salable due to presence of lime gypsum. Total fly ash volumes needed for disposal will be less than in Options 2 and 3. Due to closure of the mine, land will be needed to establish an ash landfill for bottom and fly ash that cannot be sold. Ash not anticipated to be hazardous.
5	Ammonia Scrubbing Forced oxidation - CMC coal	No change in quantity of bottom or fly ash generated. If careful control of the ammonia scrubbing process does not occur, large quantities of fly ash will need to be landfilled. Poor control of ammonia scrubbing process may contaminate the ash with unacceptable quantities of ammonia, thus preventing its sale. Significant changes in the metal content of the coal, though not expected, may contaminate the ammonium sulfate product and limit its sale. Ash is not anticipated to be hazardous.
6	Limestone Scrubbing Forced oxidation - CMC coal	No change in quantity of bottom or fly ash generated. Poor operation of a limestone based scrubbing process may contaminate the gypsum with unacceptable concentrations of chlorides thus preventing its sale and necessitating landfilling of the gypsum product. Ash and non-wallboard quality gypsum are not anticipated to be hazardous.
7	Natural Gas	This process would produce essentially no solid wastes for disposal.
8	Limestone Forced Oxidation, 90% removal for one unit	No change in quantity of bottom or fly ash generated. Poor operation of limestone based scrubbing process may contaminate the gypsum with unacceptable concentrations of chlorides thus preventing its sale and necessitating landfilling of the gypsum product. Ash and non-wallboard quality gypsum are not anticipated to be hazardous.
9	Limestone Forced Oxidation, 50% removal each unit	No change in quantity of bottom or fly ash generated. Poor operation of limestone based scrubbing process may contaminate the gypsum with unacceptable concentrations of chlorides thus preventing its sale and necessitating landfilling of the gypsum product. Ash and non-wallboard quality gypsum are not anticipated to be hazardous.
10	Ammonium Sulfate Forced Oxidation, 90% removal for one unit	No change in quantity of bottom or fly ash generated. If careful control of the ammonia scrubbing process does not occur, large quantities of fly ash will need to be landfilled. Poor control of ammonia scrubbing process may contaminate the ash with unacceptable quantities of ammonia, thus preventing its sale. Significant changes in the metal content of the coal may contaminate the ammonium sulfate product and limit its sale. Ash is not anticipated to be hazardous.
11	Ammonium Sulfate	No change in quantity of bottom or fly ash generated. If careful control of the ammonia

	Forced Oxidation, 50% removal each unit	scrubbing process does not occur, large quantities of fly ash will need to be landfilled. Poor control of ammonia scrubbing process may contaminate the ash with unacceptable quantities of ammonia, thus preventing its sale. Significant changes in the metal content of the coal may contaminate the ammonium sulfate product and limit its sale. Ash is not anticipated to be hazardous.

8.1.4.6 Energy Impacts of the SO_2 Control Options

Energy consumption

The annual quantity of fuel consumed by the Centralia Plant is dependent on the annual plant capacity. Each of the 3 fuels considered in the SO_2 emissions reduction options will provide adequate energy to the plant to produce the Centralia Plant's rated capacity of electricity. The use of imported coal will allow the consumption of less total coal in terms of tons per MW, but this is due entirely to the slightly higher Btu content of the imported coal. The use of natural gas will significantly reduce emissions of all pollutants but the ability of the current natural gas pipeline system to transport gas to the plant is in question. The Plant would require 25% of the total existing pipeline capacity resulting in reductions in available gas supply for residential, industrial, and commercial uses.

At a 70% capacity factor, the Centralia Plant requires 86,030,734 million Btu per year. This can be provided by burning 4,600,574 tons per year of imported coal; 4,500,000 tons per year of local mine coal and 1,003,000 tons per year of imported coal (current plant operations); or 81,934 million cubic feet per year (321 million cu. ft. per day) of natural gas. At an 84% capacity factor, the Plant would require 103,236,880 million Btu per year and a commensurately higher quantity of fuel.

Impact on Scarce Fuels

The Centralia Mine coal fields are quite extensive and have a considerable quantity of coal in them. However there is a limited quantity of coal within current economic reach of the mining operation. The known quantity of coal in this area exceeds the currently projected lifetime of the Centralia Plant. Centralia Plant lifetime is tied to the economically available coal of the mine.

The Powder River Basin coal fields are also quite extensive and the quantity of coal in those fields is more than this facility can consume within its projected lifetime. However, this coal is also a desirable source of coal for coal fired power plants located in the eastern U.S. The coal has a relatively low sulfur content in addition to its relatively high Btu content. The low sulfur content of this coal makes it an attractive means for old, large coal-fired power plants in the eastern U.S. to comply with the federal Acid Rain Program SO_2 emission limitations. Thus, there is considerable demand on the Powder River Basin coal fields to supply coal to facilities throughout the country.

Natural gas availability is constrained by the capacity of the Northwest Pipeline Company to transport natural gas from its sources in Canada and the Colorado/Utah/New Mexico area. During full load operation, the Centralia Plant would require 25% of the current pipeline capacity to supply its gas needs. Long-term availability of natural gas in the quantities needed by the Plant is another concern and risk for the Centralia Plant.

Energy Consumption Impact of Control Options

Each of the control options that utilize add on control equipment will consume electricity. Electricity will be used to power fans, conveyor belts, water pumps, grinders and solids separation equipment. Diesel oil used to power locomotives will be used to transport limestone, ammonia, or lime to provide chemicals for controlling emissions from the closest port of call. The electricity for powering the control equipment will come from the plant generating capacity, and reduce the net electrical output from the facility. Diesel oil used to power the locomotives will come from ever diminishing national and world supplies of petroleum.

The use of external coal or natural gas requires the use of diesel oil (for transporting coal from the mines) or natural gas (for operation of compressor stations) to transport these fuels to the facility.

Local Economic Impacts

The economic impacts of the various control options extend beyond the costs of installation and operation of the various control options. Economic impacts of the mine range from local employment and contracting for locally supplied services to taxes paid to the local and state government. This review will not evaluate those effects in depth but will concentrate on the economics related to closure of the mine that currently supplies coal to the Centralia Plant. For more information on the regional impacts of the Centralia Plant, the legislative record for House Substitute Bill (HSB) 1257 should be reviewed. HSB 1257 is included as Appendix _*, however, the bill does not contain a discussion of regional impacts.

Three control options that are currently under consideration would result in the closure of the Centralia Mine coal fields. Closure of the mine would result in a significant adverse impact on the local economy and employment in Lewis County and adjacent parts of Thurston County (Ref. 29, Appendix I). The mine currently employs about 510 people. These people collect wages amounting to $37.8 million which would be lost from the local economy if the mine were to close. Additionally it has been estimated that the mine supplies $112.8 million (including direct wages to employees) to the state's economy plus nearly $14 million in state and local tax revenues. Closure of the mine in favor of other sources of energy to operate the Centralia Plant is estimated to eliminate all of the current mine employment and its resulting economic benefits for the Centralia area of Lewis County and the adjacent parts of Thurston County.

EPA has prepared guidance for evaluating BART for coal fired power plants (Ref. 33). In developing these guidelines, EPA contemplated that switching fuel sources might be one result of determining BART for a coal-fired power plant. As a result of this forward thinking, EPA states in that guidance:

> *A control system which requires the use of a fuel other than locally or regionally available coal should be discouraged if such requirement causes significant local economic disruption or unemployment.* (Ref. 33, p. 16)

Irreversible Natural Resource Commitments

All of the emission control options irrevocably consume limited natural resources in the production of electricity and in the control of SO_2 emissions from the Centralia Plant.

The add-on emission control options consume either limestone or ammonia to control SO_2. Limestone is a mineral resource that is consumed in the process of controlling SO_2 emissions from this or any other coal-fired power plant.

The lime based spray dryer options (No. 2, 3, and 4), in addition to consumption of limestone, also consume fossil energy sources to produce lime. This adds to the Centralia Plant's impact on the consumption of fossil energy sources.

The production of ammonia involves the consumption of natural gas in the production of ammonia.

The use of natural gas as a fuel to produce electricity consumes this fossil fuel. Currently Northwest Pipeline Company purchases its gas supplies from Canada and production fields in the western Colorado/eastern Utah area, and northwestern New Mexico areas of the US. All of these areas have limited production lifetimes. As supplies in the current production areas decline, new production areas will have to be found and the cost of the gas from those new fields will cost commensurately more.

8.1.4.7 Rationale for Favoring Ammonium Sulfate Forced Oxidation Technology Option

In selecting one of the emission control options as meeting the selection criteria contained in the EPA BART guidance, the following criteria were considered:

(1)Visibility improvement potential is to be analyzed with the PLUVUE model (a plume visibility model).
(2)Energy impacts of each control option, including the impact of a control option on the use of locally available coal.
(3)Environmental impacts of each control option.
(4)Economic impacts of each control option.

EPA recommends the use of both an array (matrix) of the control options and a logic network used in the decision making process (Ref. 33, Page 21). No summary matrix of control options and their effects has been prepared.

Instead of using PLUVUE, the NPS used a meso-scale dispersion model (MESOPUFF) to estimate the potential light absorption based on analyses of IMPROVE monitoring station fine particulate data. (Refs. 67 & 68)

To select an emission control technology and thus establish appropriate emission limits the following principles were used:
(1) Modeled visibility impact on < 10 days per year due to plant emissions.
(2) Continued operation of the Centralia Mine.
(3) Minimum visibility impairment at lowest annual and capital costs.
(4) Maximum emissions control at lowest annual and capital costs per ton of SO_2 removed.

Reduction of potential visibility impacts to less than 10 days per year (more than a two-thirds reduction in potential visibility impairment from 1994 emission levels) must be considered significant progress in reducing visibility impacts due to this source. Therefore, less than 10 days per year of visibility impacts is a reasonable level for reducing the number of viable control technologies from which to choose BART-like technology.

Maintaining continued operation of the Centralia Mine is an important consideration. The BART guidance from EPA discourages mine closure options that have the potential for significant local economic disruption or unemployment. The Washington State law designated HSB 1257 is a jobs and environment bill that anticipates continued operation of the mine to provide both local employment and tax revenues. This law also contains relatively severe monetary penalties for closure of the mine and the power plant.

The costs of visibility improvement can be measured as the cost of emission reduction per day of impairment reduced. Since the BART program is intended to reduce adverse impacts on visibility, an appropriate criterion is to maximize the reduction of potential visibility impairment but at the lowest cost per day of impairment reduced.

Achieving the maximum level of emissions control at the lowest cost per ton of pollutant removed is a common goal of emissions reduction programs ranging from BACT to development of NSPS and NESHAP regulatory levels.

These principles eliminated all pollutant control options that resulted in SO_2 emissions greater than 27,000 tons per year. Eliminating all options that would close the CMC mine eliminated three more of the options. This leaves four options, two lime spray dryer options which use Centralia coal, Ammonium Sulfate Forced Oxidation, and Limestone Forced Oxidation.

Table 8.1-8

SO_2 Options and Potential Visibility Improvement

Control option Number	Control Option Description	< 10 days impact?	Continued mine operation?
1	All external coal, no add-on controls	Y	N
2	Lime spray dryer scrubbing using existing ESPs and local coal	Y	Y
3	Lime spray dryer scrubbing using new baghouse and local coal	Y	Y
4	Lime spray dryer scrubbing using existing ESPs and all external coal	Y	N
5	Ammonium Sulfate Forced Oxidation with local coal, 90% removal	Y	Y
6	Limestone Forced Oxidation with local coal, 90% removal	Y	Y
7	Conversion to Natural Gas	Y	N
8	Limestone Forced Oxidation with local coal, 90% removal on 56% of exhaust gas flow	N	Y

9	Limestone Forced Oxidation with local coal, 50% removal on each unit	N	Y
10	Ammonium Sulfate Forced Oxidation with local coal, 90% removal on 56% of exhaust gas flow	N	Y
11	Ammonium Sulfate Forced Oxidation with local coal, 50% removal on each unit	N	Y

The emission reduction costs per day of visibility improvement from the last column of Table 8.1-5 are plotted for all 11 options in Figure 8.1-2. As this figure shows, no clear pattern emerges to rank or order the emission reduction options. However, among those options which meet the visibility and continuation of Centralia coal mine goals, Option 5 has the lowest annual cost and provides the most days of improvement followed by Option 6, which are two of the 90% removal options.

In Figure 8.1-3, the annualized cost effectiveness is plotted against the annual emission reduction for all 11 options considered. The annual costs do not include the total cost of fuel, which would dwarf all emission control costs, but only the difference in fuel costs compared with continued use of Centralia Mining Company coal. This annual cost effectiveness plot shows Options 5 and 6 best meet the criteria of low cost per ton of emissions removed and high emissions removal. However, Option 3 provides the same level of emissions removal but at a slightly higher operating cost.

As previous discussion indicates, Options 3, 5, and 6 have similar water quality, water quantity and solid waste impacts. However, the lime spray dryer technology, Option 3, has the most continuing adverse impacts by generating a solid waste that must be landfilled, whereas Options 5 and 6 are designed to produce a marketable product. In addition to the various impacts and potential benefits discussed above, the use of the Ammonium Sulfate Forced Oxidation technology (Option 5) has the potential to release ammonia into the environment. Ammonia is a toxic gas that can cause a number of health effects, and can impact both aquatic and terrestrial animals and plants at relatively low concentrations. Discharge of ammonia into the Chehalis River basin by wastewater dischargers has been severely limited. If a spill of ammonia during the late summer reached Big Hanaford Creek, Washington Department of Ecology spill response personnel would expect to see dead fish in the creek. Depending on the quantity of ammonia that reaches the creek, a fish kill could extend all the way to the Chehalis River. In addition, workers around the plant could suffer impaired breathing and other mucous membrane ailments due to an ammonia spill.

In spite of the potential spill problems involved in the handling and use of ammonia, fertilizer manufacturing and blending operations in Washington handle far more ammonia than the Centralia Plant would use without accidental releases of ammonia. In light of the safe manufacture, storage, and use of ammonia, the potential risk of adverse effects from an ammonia spill do not appear substantial enough to eliminate this technology from consideration.

Overall, Option 5, Ammonium Sulfate Forced Oxidation using Centralia Mine coal, appears to be the most cost effective emission control technology for this facility to achieve the desired visibility improvements. But Option 6, the Limestone Forced Oxidation system, can achieve the same emission rate at only slightly higher costs. At the Centralia Plant, the use of either of these technologies would result in the following emissions:

Limiting Factor	70% Capacity Factor	84% Capacity Factor	CDM Target Solution
Uncontrolled Emissions Rate, tons/yr	88,681*	106,417*	--
Controlled Emissions Rate, tons/yr	8,868	10,642	10,000
% Removal Through Control Device	90%	90%	90% +
Controlled Rate (lb/MBtu)	0.21	0.21	--

* Based on uncontrolled emissions information in 1997 RACT Submittal.

Figure 8.1-2

Cost of Potential Visibility Improvement

Figure 8.1-3

Annual Cost Effectiveness

8.1.4.8 SO_2 Conclusion

Based on the above information and the criteria required to perform a BART review, the appropriate BART-like technology would be the use of ammonium sulfate forced oxidation flue gas desulfurization technology. This emissions control technology provides the same level of SO_2 emissions removal as the Limestone Forced Oxidation technology, but at a slightly lower cost per ton of SO_2 controlled. The Limestone Forced Oxidation technology was used as the basis of the CDM group=s negotiated emission limitation. However, EPA BART regulations (40 CFR 51.300, et seq.) define BART as an emission limitation. The appropriate BART emission limitation through the Ammonium Sulfate Forced Oxidation system would be 90% removal of SO_2 emissions and an annual average of 0.21 lb SO_2/MBtu of coal burned. This level of emissions control is greater than what would be required under the default BART limitation contained in EPA's BART guidance document. This default limitation is identical to the limitation contained in 40 CFR 60.40a (Subpart Da). The "default" emission limitation is 70% reduction of the potential SO_2 emissions with an emission limit of less than 0.6 lb SO_2/MBtu (40 CFR 60.43a(a)(2)).

The Collaborative Decision Making group negotiated a proposed emission limitation of 10,000 tons SO_2 per year, 365 day rolling total. This is potentially a much more stringent limitation than the lb/MBtu limitations given above. The reasons for this are that the 10,000 tons/yr limitation is an absolute limitation that includes all SO_2 emissions including those from startup, shutdown and control system upsets. The more common lb/MBtu limitations are >relative= limitations and normally do not include startup or shutdown emissions or emissions during control system upsets. A source with a lb/MBtu limitation has a >relative= limit in that it controls emissions related to the coal combustion rate, but does not have an absolute limit on the tons per year of SO_2 that can be emitted. In other words, the total quantity of emissions varies year to year based on actual operating level of the facility. If the Centralia Plant were to increase its electrical production rate to an annual capacity factor of 84%, the annual emissions from the plant with emission controls capable of meeting a 0.21 lb/MBtu limitation (and providing 90% removal) would be 10,642 tons/yr. This is considerably higher than the rate of 8,868 tons/yr resulting from the same control efficiency at the 70% capacity factor used in the comparisons of emission control technologies.

As the capacity factor of the Centralia Plant rises above 70%, the ability of the plant operators to sustain an unplanned or emergency scrubber outage of over a few hours becomes seriously constrained. As the annual tons/yr emissions limitation is approached the plant operators may have no choice but to shut down one or both boilers to prevent exceeding established emission limits. In addition to providing some relief from various taxes, HSB 1257 also includes some severe tax deferral penalties for emitting over 10,000 tons/yr of SO_2. These penalties are significantly higher than could be levied by the environmental agencies under current enabling legislation for the same instance of noncompliance.

The proposed BART limitations for the Navajo Power Plant, which is the only facility in the nation to have undergone a formal BART review, resulted in a proposed limitation of 0.30 lb SO_2/MBtu and 70% reduction of the potential SO_2 emissions. A negotiated settlement replaced the proposed BART limitations and established an emission limit for Navajo of 0.10 lb SO_2/MBtu, evaluated as a rolling 365 boiler day average. The CDM Target Solution of 10,000 tons/yr is equivalent to 0.21 lb/MBtu, annual average, at 70% plant capacity factor.

The negotiated emission limitation termed the "CDM Target Solution" is not dependent on actual plant usage. Thus, it is an absolute limit and is more restrictive than a BART limitation established consistent with the NSPS maximum allowed emission rates.

8.2 RACT/CDM Emission Limits Compared to NSPS

In the process of determining RACT for the Centralia Plant, the owners requested that SWAPCA make a BART determination for the Plant's emissions. This request was to determine if the emissions limitations proposed in the Collaborative Decision Making (CDM) Target Solution would meet or exceed the requirements that represent Best Available Retrofit Technology (BART) emission limits. The EPA guidance on determining BART for existing coal fired power plants (Ref. 33) notes that an agency can establish as BART the emission limits of 40 CFR 60.40a (Subpart Da, NSPS for large steam electric generating units) with significantly reduced justification compared to setting BART emission limits through a more rigorous analysis. To establish BART under the rigorous process, an agency considers the costs of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility anticipated to result from application of emission controls.

8.2.1 RACT/CDM/NSPS Emission Limits

The CDM Target Solution for SO_2 was a limit of 10,000 tons/yr, annual total, both units combined. The NSPS (40 CFR 60.43a) emission limit is 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.6 lb/MBtu) heat input on a 30-day rolling average initial demonstration, and 30 successive boiler operating days long term compliance. The RACT emission limitation for SO_2 is established as the CDM Target Solution of 10,000 tons/yr which is equivalent to an emission rate of 0.21 lb/MBtu at a 70% capacity factor.

The CDM group identified low NO_x burners that could achieve compliance with the Phase II Acid Rain Program as the target solution for NO_x. At the time this target solution was developed, the Phase II program limitation for each unit was 0.38 lb/MBtu, annual average. This limit is approximately the same as the NSPS limitation of 0.50 lb/MBtu, 30 day average, when accounting for the different averaging periods. The proposed RACT emission limit for NO_x is 0.30 lb/MBtu, annual average, both units averaged together.

The CDM group did not develop a target solution for particulate matter. The NSPS allows an emission rate of 0.03 lb/MBtu (about 0.018 grains per dry standard cubic foot (gr/dscf)). This rate is higher than the average emission rate of 0.005 gr/dscf (about 0.0083 lb/MBtu) currently emitted by the Centralia Plant. The RACT limitation for particulate matter is 0.010 gr/dscf which reflects the capabilities of the existing dual series ESP control system.

8.2.2 Emission Limit Averaging Periods

EPA permitting guidance (Ref. 61) requires the use of emissions averaging periods that are as short as possible but long enough to account for normal operational fluctuations. In developing the NSPS for coal fired power plants, EPA recognized, through the analysis of continuous emission monitor (CEM) data for NO_x and SO_2, that hour to hour and day to day fluctuations in emission rates were unpredictable. EPA found that the effectiveness of SO_2 emission controls was more predictable over longer averaging periods. Based on the data available during the development of the NSPS, EPA chose to use a rolling, 30 boiler operating day average, as the measurement method for limiting emissions.

When developing the CDM Target Solution emission limits for SO_2, the CDM group considered the NSPS limits, the Navajo Power Plant decision (Ref. 62), and other recent permitting decisions, for guidance on how to craft emissions limitations for the Centralia Plant target solution. For example, the Navajo Power Plant final decision resulted in an SO_2 emission limit 0.10 lb/MBtu, averaged over 365 boiler operating days, rolled daily.

The CDM Target Solution SO_2 emission limit is a tons per year (tons/yr) limitation rolled monthly unless a violation occurs which then allows evaluation for each day on a 365 day rolling summation. The Centralia Plant has acknowledged that, to meet the rolling tons/yr limit, plant personnel will need to evaluate their annual total SO_2 emissions status daily in order to prevent non-compliance.

Significant differences in how much of the actual emissions are evaluated against the limitations are apparent when comparing the CDM Target Solution emission limits to the NSPS limits. The CDM's proposed annual tonnage limitation for SO_2 includes all boiler emissions, regardless of the operating conditions under which they occur. In contrast, the NSPS limitation excludes emissions during startup, shutdown, malfunctions, and days with less than 24 hours of boiler operations. In this regard, the CDM SO_2 limitation is significantly more inclusive and restrictive than the NSPS limitation.

8.2.3 Discussion

40 CFR 51.302(c)(4) requires the use of EPA developed guidance for states to determine BART emission limits for coal fired power plants. This BART guidance (Ref. 33) states that application of emission limits equivalent to the applicable NSPS limit(s) can be defined as BART and do not require a detailed evaluation to justify their selection. Therefore, no additional analyses of technology, environmental effects, or economics need be done and the resulting NSPS limitations can then be incorporated into the State Implementation Plan (SIP) as the BART limitations for the facility in question.

Visibility Considerations

The EPA guidance states that a visibility modeling analysis be performed. This analysis is to determine if the application of the NSPS will result in perceptible improvements to visibility. The plume visibility evaluation required in the guidance has not been performed. The BART guidance requires the use of a simple plume visibility model which is used for screening visibility impacts for prevention of significant deterioration (PSD) permitting activities.

The National Park Service (NPS) and Forest Service assert that there is some uniform visibility impairment attributable to the Centralia Plant. To arrive at this assertion, NPS performed dispersion modeling of the Centralia Plant's emissions and additional analyses of monitoring data for fine particulate matter as reported in the PREVENT study (Ref. 21). Based on the dispersion modeling performed by Vimont (NPS) (Ref. 18), the 1999 visibility impact of 48 days per year and the 1990 estimate of about 30 days per year of impacted visibility due to Centralia Plant emissions would be reduced to 6 days at the NSPS emission level and less than 2 days at the CDM emissions level. The evaluation of the PREVENT data by the NPS indicates that the percentage of light scattering caused by sulfates attributable to the Centralia Plant is 16% at 1990 emission rates. Reduction to the NSPS level of emissions results in Centralia Plant's SO_2 emissions contributing about 6% of the light scattering potential. Emission rate reductions to the CDM Target Solution level of emissions result in Centralia Plant's SO_2 emissions contributing about 2% of the light scattering potential. Based on either of these analyses, a significant reduction in potential visibility impairment occurs due to emissions reductions to the NSPS level, and a more significant reduction in potential impairment occurs at the CDM Target Solution emissions level.

The PREVENT study collected ambient particulate data during 1990. SO_2 emissions during 1990 totaled 58,297 tons and the plant operated at a capacity factor of 63%. The Vimont analysis (Ref. 18) was based on 1994 emissions of about 67,500 tons/yr while the plant operated at a capacity factor of 84%.

Controls on particulate matter emissions are currently better than the NSPS level of control. Thus, no additional visibility or other improvements can be achieved by applying the NSPS limits to this pollutant.

Emissions Limits

The NSPS limitations as applied to the facility would be:

	lb/MBtu	**% reduction from potential emissions**	**Other limits**
SO_2	0.6*	70%*	--
NO_x	0.5*	65%*	--
Particulate (TSP)	0.03**	99%	20% Opacity, 6 min. avg.

*30 boiler operating day average.
**Evaluated during source tests.

The CDM Target Solution emission levels are:

	lb/MBtu	**Tons/yr**
SO_2	Not established*	10,000*
NO_x	0.38**	Not established***
Particulate	Not established	Not established

* Equivalent to about 0.21 lb/MBtu, based on the annual average limit.
** Represents 15% reduction from Early Election level of 0.45 lb/MBtu.
*** Approximately 16,346 tons/yr at 70% capacity factor.

Comparison of Emission Limits

A comparison of the RACT/CDM Target Solution emission limits and the NSPS emission limits is provided below for the Centralia Plant for the calendar year of 1996. Since the emission limits proposed by the CDM process are annual totals and averages, and the NSPS limits are 30 day averages, the emission limit averaging periods must be considered when comparing the RACT/CDM Target Solution and NSPS emission limits.

An analysis was performed on Plant emissions data and on this same data modified to meet the NSPS emission limit requirements. These results were then compared with the NSPS and CDM limitations. The evaluation used the emissions and operating characteristics of the plant during 1996 as reported to SWAPCA and to EPA. From the reported 1996 emissions, annual and 30 operating day averages were computed consistent with the NSPS emission limits and evaluation methodology. Results of this analysis are presented in Table 8.2-1 for Units 1 and 2 separately. The emissions summaries are based on operating days only, which are those calendar days with 24 hours of unit operating time. Results in Table 8.2-1 may not appear consistent with other annual plant emissions statistics for 1996 because the evaluation method does not consider partial days of operation with fewer than 24 hourly data values.

As summarized from Table 8.2-1, the Centralia Plant exhibited the following operating characteristics in 1996 as determined by the evaluation method defined in the NSPS for coal fired power plants:

	Emission Rate (lb/MBtu)	**Annual Emissions (tons/yr)**	**Other**
Capacity Factor	--	--	69%
SO_2, Unit 1	1.49	35,624	
SO_2, Unit 2	1.53	36,976	
NO_x, Unit 1	0.45	10,092	
NO_x, Unit 2	0.46	10,543	

To meet the NSPS limitations, add-on SO_2 control equipment that provides 70% removal and simple combustion modifications that provide a 15% reduction from current NO_x emission levels were incorporated in the above emissions characteristics. This results in predicted SO_2 and NO_x emissions from the Centralia Plant as follows:

	SO_2			NO_x		
	Annual Average (lb/MBtu)	**Max. 30 day Average (lb/MBtu)**	**Annual Tons (tons/yr)**	**Annual Average (lb/MBtu)**	**Max. 30 day Average (lb/MBtu)**	**Annual Tons (tons/yr)**
Unit 1	0.45	0.52	10,687	0.36	0.49	8,578
Unit 2	0.47	0.51	11,093	0.37	0.38	8,961
Unit 1 and 2 average	0.46	0.52	10,890	0.37	0.44	----
TOTAL	---	----	21,780	--	--	17,539
CDM Limits	----	----	10,000	0.38	---	----

As a comparison of the CDM Target Solution limit and the NSPS in the above table indicates, the CDM Target Solution emission limit for SO_2 is more restrictive than the NSPS emission limit. Application of the SO_2 NSPS would allow the Centralia Plant to emit 21,780 tons/yr, whereas the CDM Target Solution limits the facility to only 10,000 tons/yr. Comparing the CDM Target Solution NO_x limit to the NSPS limit indicates that the NSPS will provide slightly better annual average emissions than the CDM Target Solution limit. However, the NO_x RACT emision limit for the Centralia Plant was set at 0.30 lb/MBtu rather than the 0.38 lb/MBtu proposed by the CDM group. Therefore, the RACT NO_x emission level at the Centralia Plant clearly exceeds the NSPS emission limit.

Capacity Factor Issues

All of the above comparisons are for 70% capacity factor. The facility has operated at up to 84% annual capacity factor which occurred in 1994. The emission limits for SO_2, NO_x, and particulate matter in the NSPS have no annual limit (i.e., tons per year), but are related directly to the annual fuel consumption and plant capacity factor. The CDM Target Solution for NO_x is consistent with the NSPS approach, employing a rate limit that depends on the fuel heat input. The CDM Target Solution for SO_2 limits the total annual tons per year of SO_2 emitted. This latter limit is unrelated to the Centralia Plant's annual capacity factor.

Under the NSPS, as the plant capacity factor increases due to increased usage of the facility, the total mass of emissions increases while still complying with a lb/MBtu limit. The following table displays operating conditions and SO_2 emissions rates for expected normal and high capacity factors. These emission values are totals for all operating hours, not just complete operating days as in Table 8.2-1. The effect of capacity factor on emissions with a rate limit compared to an absolute tonnage limit is clearly demonstrated.

	70% Capacity Factor	**84% Capacity Factor**	**NSPS @ 70% Capacity Factor**	**NSPS @ 84% Capacity Factor**
1999 uncontrolled emissions rate*, ton/yr	88,861	106,417	88,681	106,417
1999 controlled emissions rate, ton/yr	8,868	10,642	26,604	31,925
CDM SO_2 limitation, ton/yr	10,000	10,000	-	-

* Based on projected uncontrolled emissions information in 1997 RACT submittal.

The BART guidance does not require further analyses beyond the content of this review. A more detailed engineering analysis of available control technology might result in selection of a control technology that would provide for a higher level of emissions reduction than required by the NSPS, but the CDM Target Solution exceeds the NSPS requirements.

Table 8.2-1

Centralia Plant Emissions Summary
Effect of Application of NSPS Emission Limits and NSPS Evaluation Method

Unit 1, 1996 Operating Characteristics

	SO_2 Emissions (lb/MBtu)	NO_x Emissions (lb/MBtu)	NO_x Emissions @ 15% Reduction (lb/MBtu)
Annual Average 1996	1.492	0.425	0.360
Annual Average SO_2 @ 70% Removal	0.449	-	-

	SO_2 Emissions (ton/yr)	NO_x Emissions (ton/yr)	NO_x Emissions @15% Reduction (ton/yr)
Annual Total 1996	35624	10092	8578
Annual Total SO_2 @70% Removal	10687	-	-

30 Day Average Statistics			
Maximum	0.521	0.582	0.495
Minimum	0.366	0.340	0.289
Median	0.453	0.408	0.347
Average	0.450	0.427	0.363
Std Deviation	0.032	0.056	0.048
Average + 2 Std. Deviation	0.513	0.539	.458

Unit 2, 1996 Operating Characteristics

	SO_2 Emissions (lb/MBtu)	NO_x Emissions (lb/MBtu)	NO_x Emissions @ 15% Reduction (lb/MBtu)
Annual Average 1996	1.533	0.440	0.373
Annual Average SO_2 @ 70% Removal	0.464	-	-

	SO_2 Emissions (ton/yr)	NO_x Emissions (ton/yr)	NO_x Emissions @15% Reduction (ton/yr)
Annual Total 1996	36976	10543	8961
Annual Total SO_2 @70% Removal	11093	-	-

30 Day Average Statistics			
Maximum	0.512	0.511	0.434
Minimum	0.398	0.393	0.334
Median	0.467	0.438	0.372
Average	0.465	0.442	0.376
Std Deviation	0.025	0.031	0.027
Average + 2 Std. Deviation	0.516	0.504	0.429

70% removal for SO_2 means the scrubber system removes only 70% of the SO_2 in the flue gas that it receives.

15% reduction for NO_x means the NO_x formation potential of the combustion system is reduced by 15 % through the use of combustion system modifications provided by an optimistic application of Level I controls or Level II controls.

8.2.4 Conclusion

The BART guidance document does not require any more analyses than what has been done in this review. The conclusions from this review are as follows:

(1)The RACT/CDM Target Solution SO_2 limitation of 10,000 tons/yr (~0.21 lb/MBtu at a 70% capacity factor), annual total, both units combined, is more restrictive than application of the NSPS emission limitation of 0.6 lb/MBtu (with 70% reduction in potential emissions) on a 30 day average.

(2)The RACT emission limit of 0.30 lb/MBtu, annual average, for NO_x exceeds the NSPS limitation of 0.50 lb/MBtu, 30 day average.

(3)The RACT limitation for particulate matter is 0.010 gr/dscf which reflects the capabilities of the existing dual ESPs, in series, control system exceeds the NSPS emission rate of 0.03 lb/MBtu (about 0.018 grains per dry standard cubic foot (gr/dscf)).

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Section 9.0

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Section 10.0

APPENDICES

Appendix A

Collaborative Decision Making (CDM) Documentation

Attached

Appendix B

House Substitute Bill 1257

Coal Fired Thermal Electrical Generation Facilities:

Assistance for Pollition Control And Abatement

Attached

Appendix C

Memorandum of Understanding Between Southwest Air Pollution Control Authority, Department of Ecology and Department of Revenue

Regarding HSB 1257

55th Legislative Session

Regular Session

Appendix D

PSAPCA Method 5

Particulate Matter Emissions Testing

Attached

Appendix E

Various NO_x Emission Rate Data Vs. Load Graphs

Attached