

STATE OF NEBRASKA

DEPARTMENT OF ENVIRONMENTAL QUALITY

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Mike Johanns
Governor

CONSTRUCTION PERMIT

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) PERMIT TO MODIFY AN AIR CONTAMINANT SOURCE IS HEREBY ISSUED TO:

Omaha Public Power District
444 South 16th Street
Omaha, Nebraska 68102-2247

FOR THE SPECIFIC CONSTRUCTION OF:

A nominal 660-megawatt coal-fired electric generating unit with supporting equipment
(Nebraska City Unit 2)

TO BE LOCATED AT:

OPPD – Nebraska City Station
7264 L Road
Nebraska City, Nebraska 68410

Pursuant to Chapter 14 of the Nebraska Air Quality Regulations, the public has been notified by prominent advertisement of this proposed modification of an air contaminant source and the thirty (30) day period allowed for comments has elapsed. This Construction Permit approves the proposed construction of a new nominal 660-megawatt coal-fired electric generating unit with supporting infrastructure, and places new emission limits on existing equipment at the existing Nebraska City Station located approximately 5 miles southeast of Nebraska City.

Compliance with this permit shall not be a defense to any enforcement action for violation of an ambient air quality standard.

This permit is issued with the following conditions:

General Conditions

- I. This permit is not transferable to another source or location. (Title 129, Chapter 17)
- II. Holding of this permit does not relieve the owner/operator of the source from the responsibility to comply with all applicable portions of the Nebraska Air Quality Regulations and any other requirements under local, State, or Federal law. (Title 129, Chapter 41)
- III. Any applicant who fails to submit any relevant facts or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. If the source wishes to

make changes at the facility that will result in change(s) to values, specifications, and/or locations of emission points that were indicated in the permit application (or other supplemental information provided by the applicant and reviewed by the Department in issuance of this permit), the source must receive approval from the Department before the change(s) can be made. In addition, any modification which may result in an adverse change to the air quality impacts predicted by atmospheric dispersion modeling (such as changes in stack parameters or increases in emission rates, potential emissions, or actual emissions) shall have prior approval from the Department. The source shall provide all necessary information to verify that there are no substantive changes affecting the basis upon which this permit was issued. Information may include, but not be limited to, additional engineering, modeling and ambient air quality studies. (Title 129, Chapter 17, Section 006, 007, & 008)

- IV. Approval to construct, reconstruct and/or modify the source will become invalid if a continuous program of construction is not commenced within 18 months after the date of issuance of the construction permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable period of time. (Title 129, Chapter 17, Section 012)
- V. The owner/operator of the source shall provide a notification to the Department of the date construction, reconstruction, or modification commenced, postmarked no later than 30 days after such date, and of the actual date of initial startup of operation, postmarked within 15 days after such date. (Title 129, Chapter 17, Section 012 & Chapter 7, Section 002.03)
- VI. The permittee shall allow the Department, EPA or an authorized representative, upon presentation of credentials to (Title 129, Chapter 8, Section 012.02):
- (A) Enter upon the permittee's premises at reasonable times where a source subject to this permit is located, emissions-related activity is conducted or records are kept, for the purpose of ensuring compliance with the permit or applicable requirements;
 - (B) Have access to and copy, at reasonable times, any records, for the purpose of ensuring compliance with the permit or applicable requirements;
 - (C) Inspect at reasonable times any facilities, pollution control equipment, including monitoring and air pollution control equipment, practices, or operations, for the purpose of ensuring compliance with the permit or applicable requirements;
 - (D) Sample or monitor at reasonable times substances or parameters for the purpose of ensuring compliance with the permit or applicable requirements.
- VII. Applicable regulations: Title 129 - Nebraska Air Quality Regulations as amended February 7, 2004.
- VIII. This permit may contain abbreviations and symbols of units of measure which are defined in 40 CFR Part 60.3. Other abbreviations may include, but are not limited to, the following: American Society for Testing and Materials (ASTM), Best Available Control Technology (BACT), Code of Federal Regulations (CFR), Compilation of Air Pollutant Emission Factors, Volume I, Stationary Point and Area Sources (AP-42), Code of Federal Regulations (CFR), Carbon Monoxide (CO), Construction Permit (CP), Continuous Emissions Monitoring System (CEMS), Continuous Opacity Monitoring System (COMS), Dry Standard Cubic Feet per Minute (dscfm),

United States Environmental Protection Agency (EPA), Flue Gas Desulfurization (FGD), Hazardous Air Pollutant (HAP), Hydrogen Sulfide (H₂S), Maximum Achievable Control Technology (MACT), Mega-watt (MW), Million British Thermal Units (MMBtu), National Ambient Air Quality Standards (NAAQS), Nebraska City Station (NCS), New Source Performance Standards (NSPS), Nitrogen Oxides (NO_x), Operating Permit (OP), Particulate Matter (PM), Particulate Matter less than or equal to 10 micrometers (PM₁₀), parts per million (PPM), Prevention of Significant Deterioration (PSD), Selective Catalytic Reduction (SCR), Sulfur Dioxide (SO₂), Total Reduced Sulfur (TRS), Volatile Organic Compounds (VOC).

- IX. Open fires are prohibited except as allowed by Title 129, Chapter 30.
- X. The source shall not cause or permit fugitive particulate matter to become airborne in such quantities and concentrations that it remains visible in the ambient air beyond the property line. (Title 129, Chapter 32)
- XI. Application for review of plans or advice furnished by the Director will not relieve the source of legal compliance with any provision of these regulations, or prevent the Director from enforcing or implementing any provision of these regulations. (Title 129, Chapter 37)
- XII. If and when the Director declares an air pollution episode as defined in Title 129, Chapter 38, Sections 003.01B, 003.01C, or 003.01D, the source shall immediately take all required actions listed in Title 129, App. I until the Director declares the air pollution episode terminated.

Specific Conditions

- XIII. Specific terms and conditions of this permit:
 - (A) This permit allows for the discharge of air contaminants from the installation (construction) of the equipment listed in Table 1. This equipment is collectively referred to as NCS Unit 2. This permit also approves the modification of the existing coal conveyer/tripper system (Emission points 105 and 106) {Title 129, Chapters 17 and 19}

TABLE 1

Emission Point	Emission Unit / Equipment ID	Nominal Size / Capacity
201	Unit 2 Boiler (20-1)	6,478 MMBtu/hr
202	SDA Lime Storage Exhaust (24-1)	2,000 acfm
203	Recycled Ash Storage (25-1)	3,850 acfm
204	Fly Ash Waste Storage Bin Vent (23-1)	3,850 acfm
207	Emergency Generator (22-1)	1,837-horsepower
208	Cooling Tower 18-cell (26-1)	335,000 gallons/min
209	Auxiliary Boiler 2 (21-1)	125 MMBtu/hr
211	Fly Ash Pneumatic Air Exhauster (23-2)	5,000 acfm
215	Activated Carbon (Hg control) Silo Exhaust (27-1)	2,000 acfm

(B) Operational and Fuel Limitations:

- (1) Limitations on the annual operating hours and allowed fuel combustion for specific NCS Unit 2 equipment are indicated in Table 2. {Title 129, Chapters 4 and 19}

TABLE 2

Equipment / Emission Point	Fuel Type Allowed	Operational Limitation
Unit 2 Boiler (201)	Sub-bituminous coal	None
Aux Boiler 2 (209), Emergency Generator (207)	Distillate fuel oil with a maximum sulfur content of 0.05 percent (0.05%) by weight	Less than or equal to 500 hours each, during any period of twelve (12) consecutive months *

* and at no time during the first 11 months after operation commences shall the sum of all the previous months usage exceed 500 hours.

- (2) Cooling Tower. The Unit 2 multi-cell tower (emission point 208) shall be equipped with high efficiency mist eliminators with a maximum total liquid drift not to exceed 0.0005 percent of circulating water flow. {Title 129, Chapter 19}
- (3) Operation of each baghouse (emission points 103, 104A, 104B, 105, 106, 107, 109, 110, 111, 202, 203, 204, 211, and 215) shall be in accordance with the following requirements:
- (a) Each baghouse shall be operated at all times associated emission unit is in operation and be equipped with an operational pressure differential indicator.
 - (b) The baghouses shall be properly installed, operated, and maintained. Manufacturer's instructions, if available, shall be kept on site and readily available to Department representatives.
 - (c) Routine observations (at least once each day of dust collector operation) shall be conducted to determine whether there are visible emissions from the stack, leaks or noise, atypical pressure differential readings, or other indications which may necessitate corrective action. Corrective action shall be taken immediately if necessary.
 - (d) Collected waste material from the fabric dust collectors shall be handled, transported, and stored in a manner that ensures compliance with Condition X.
- (4) Operation of the Unit 2 baghouse (emission point 201) shall be in accordance with the following requirements:

- (a) The baghouse shall be operated at all times the associated emission unit is combusting coal and shall be equipped with an operational pressure differential indicator and bag leak detection system.
 - (b) The baghouse shall be properly installed, operated, and maintained. Manufacturer's instructions, if available, shall be kept on site and readily available to Department representatives.
 - (c) The bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations, and in accordance with the guidance provided in "Fabric Filter Bag Leak Detection Guidance," EPA-454/R-98-015, September 1997.
 - (i) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.
 - (ii) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.
 - (iii) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor(s) and provide notification when an increase in particulate matter emissions over a preset level is detected. Corrective action shall be taken immediately if necessary.
 - (d) Routine observations (at least once each day of dust collector operation) shall be conducted to determine whether there are visible emissions from the stack, leaks or noise, atypical pressure differential readings, or other indications that may necessitate corrective action. Corrective action shall be taken immediately if necessary.
- (C) Stack Dimensions: Final stack parameters shall meet the following dimensions as listed in Table 3. Within 180 days after construction of this project is completed, the permittee shall determine the actual stack exit point dimensions. {Title 129, Chapters 4 and 19}

TABLE 3

Emission Point	Emission Unit / Equipment ID	Minimum Stack Height (ft)	Stack Exit Point Maximum Inside Diameter (ft)
201	Unit 2 Boiler (20-1)	400	23.0
209	Auxiliary Boiler 2 (21-1)	65	3.5
207	Emergency Generator (22-1)	12	1.33

- (1) Within 10 days after determining the actual stack exit point dimensions, the permittee shall certify in writing to the Department that the exit point dimensions comply with the values of Table 3.

- (2) The certification shall contain the actual diameter and height of the stacks as-built. A copy of this certification shall be retained on site and be made available for inspection by the Department upon request.

(D) Emission Limitations:

- (1) The permittee shall not cause the discharge of air contaminants into the atmosphere in excess of the amounts listed in Table 4. {Title 129, Chapter 4, 19, and 27}

TABLE 4

Emission Point	Emission Unit (ID)	Emission Limit	Comments
105	Tripper dust collector (9-1)	PM: 0.01 grains/dscf	test method average ^a
106	Tripper dust collector (9-2)	PM: 0.01 grains/dscf	test method average
109	Crusher dust collector (8-1)	PM: 0.00826 grains/dscf	test method average
110	Crusher dust collector (8-2)	PM: 0.00826 grains/dscf	test method average
201	Unit 2 Boiler (20-1)	PM: 0.018 lb/MMBtu ^b	test method average
		SO ₂ : 0.095 lb/MMBtu ^c	30-day rolling average
		SO ₂ : 0.163 lb/MMBtu	24-hr rolling average
		SO ₂ : 0.48 lb/MMBtu	3-hour rolling average
		NO _x : 0.07 lb/MMBtu ^d	30-day rolling average
		CO: 0.16 lb/MMBtu	3-hour rolling average
		VOC: 0.0034 lb/MMBtu	test method average
		H ₂ SO ₄ : 0.0042 lb/MMBtu	test method average
		HCl: 0.0008 lb/MMBtu	test method average
		Fluorides: 0.0004 lb/MMBtu ^e	test method average
		Hg: 18 x 10 ⁻⁶ lb/MW hr ^f	12-month rolling ave.
202	SDA Lime Storage Exhaust (24-1)	PM: 0.01 grains/dscf	test method average
203	Recycled Ash Storage (25-1)	PM: 0.01 grains/dscf	test method average
204	Fly Ash Waste Storage Vent (23-1)	PM: 0.01 grains/dscf	test method average
211	Fly Ash Waste Dust Collector (23-2)	PM: 0.01 grains/dscf	test method average
215	Activated Carbon Silo Exhaust (27-1)	PM: 0.01 grains/dscf	test method average

^a Test method average is the average of three (3) test runs (typical for all)

^b PM limit includes filterable plus condensable particulate matter

^c Emission limit does not apply during periods of startup, shutdown, or malfunction

^d Refer to Condition XIII.(D)(2)

^e Fluorides, measured as hydrogen fluoride (HF)

^f Based on gross energy output. This permit limit is based on a case-by-case MACT determination. It is subject to revision in the event of a final federal MACT standard for mercury.

- (2) During the first 18 months following initial startup (demonstration period), the Unit 2 Boiler shall not emit NO_x exceeding 0.12 lb/MMBtu on a 30-day rolling average instead of 0.07 lb/MMBtu as listed in Table 4.
- (a) During this demonstration period, the owner or operator shall prepare and demonstrate compliance with a “NO_x Compliance Plan” (Plan), prepared in cooperation with the SCR system manufacturer, installer, and operator. The Plan shall be prepared and submitted to the Department for approval within 90 days following initial startup. The Plan shall outline operating and maintenance practices, system performance characteristics and evaluation methods, and procedures necessary to progress from initial SCR system startup to full permit compliance before the demonstration period expires. A log shall be completed for all activities associated with the “tuning” of the SCR system to show compliance with the Plan. Within 14 months after initial startup, an interim status report shall be submitted to the Department indicating the current SCR system performance and progress toward compliance with the Table 4 emission limit.
- (b) If the source does not expect to meet the NO_x emission limits in Table 4 after the 18-month demonstration period has elapsed, an SCR Performance Report shall be submitted to the Department no less than 30 days prior to the end of the demonstration period. This report shall include a performance assessment of the SCR system, documentation to show compliance with the Plan, NO_x CEMS data (including the minimum NO_x emission rate, in lb/MMBtu, that was achieved during the demonstration period), a detailed summary of the NO_x performance achieved at other existing utility boilers burning subbituminous Powder River Basin (PRB) coal, and any other information as necessary to justify why the emission limit can not be achieved.
- (c) If the Unit 2 boiler and other similar units burning PRB coal are unable to achieve the NO_x limit in Table 4, the limit may be subject to revision after the opportunity for public comment.
- (3) Opacity Limitations.
- (a) Opacity from each emission point, except Unit 2 boiler (201) and auxiliary boiler (209), shall not equal or exceed 20 percent pursuant to Title 129, Chapter 20, Section 004 and 40 CFR 60.252(c).
- (b) Opacity for the Unit 2 boiler (201) and auxiliary boiler (209) shall not exceed 20 percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity pursuant to 40 CFR 60.42a(b) and 40 CFR 60.43b(f). The opacity standard shall not apply during periods of startup, shutdown, or malfunction, pursuant to 40 CFR 60.46a(c) and 40 CFR 60.43b(g).
- (4) Startup, Shutdown, and Malfunction Requirements: Any excess emissions resulting from startup, shutdown, or malfunction type conditions shall be addressed in accordance with Nebraska Title 129, Chapter 35. Records shall be

kept of such startup, shutdown, and malfunction periods as specified under Condition XIII.(I)(3)(h).

- (E) **Notification:** The permittee shall provide to the Department and EPA Administrator written notification as follows in accordance with 40 CFR 60.7 and 40 CFR 63.9:
- (1) A notification of the date construction commenced for all NSPS affected facilities (Unit 2 boiler, auxiliary boiler 2, coal storage/conveying) postmarked no later than 30 days after such date, per 40 CFR 60.7(a)(1).
 - (2) A notification of the actual date of initial start up of the equipment postmarked within 15 days after such date, per 40 CFR 60.7(a)(3).
 - (3) Any other notification requirements of 40 CFR 60.7, should they be applicable to the facility.
 - (4) Notification for the auxiliary boiler 2 in accordance with 40 CFR 63.7506(a)(1).
 - (5) Notification for the emergency generator in accordance with 40 CFR 63.6590(b).
- (F) **Testing Requirements:**
- (1) Initial performance tests shall be conducted and the results submitted to demonstrate compliance with the applicable conditions and limitations in this permit within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. Refer to Table 5 for a summary of initial performance testing requirements.

TABLE 5 – Initial Performance Testing Summary

Emission Point(s)	Emission Unit (ID)	Initial Performance Testing Requirements / Demonstration Method	
105, 106	Tripper Dust Collectors (9-1, 9-2)	PM: Opacity:	Method 5 (filterable PM only) Method 9 (per NSPS Subpart Y)
109, 110	Crusher Dust Collectors (8-1, 8-2)	PM:	Method 5 (filterable PM only)
201	Unit 2 Boiler (20-1)	PM: SO ₂ : NO _x : CO: VOC: Fluorides: H ₂ SO ₄ : HCl: Hg: Opacity:	Method 5 & Method 202 (condensables) CEMS ^a {40CFR60.48a(c)(5)} or Method 19 CEMS ^a {40CFR60.47a(c)(2)} CEMS ^a or Method 10 Method 25 Method 26, also report fluorine ppm in coal Method 8, also report SO ₂ rate during this test Method 26, also report chlorine ppm in coal CEMS or test method, see Condition XIII.(F)(6) Method 9 or COMS ^a {40CFR60.11(b)}
202, 203,	Baghouses	PM:	Method 5 (filterable PM only)

TABLE 5 – Initial Performance Testing Summary

Emission Point(s)	Emission Unit (ID)	Initial Performance Testing Requirements / Demonstration Method
204, 211 and 215		Opacity: Method 9
209	Auxiliary Boiler 2 (21-1)	Opacity: Method 9 or COMS ^a {40CFR60.11(b)} SO ₂ : Use initial fuel supplier certifications
207	Emergency Generator (22-1)	Opacity: Method 9 at 100% load

^a refer to Condition XIII.(G)(1)

^b testing shall be done simultaneously prior to the control devices and at the boiler stack

- (2) At least 90 days prior to the date of testing, the permittee shall develop and submit to the Department a formal “Test Protocol”. This “Test Protocol” shall include, as a minimum, the following items:
 - (a) A test plan detailing the methods and procedures that will be used for testing each emissions point;
 - (b) A test schedule describing the tentative agenda as to when testing will occur;
 - (c) A description as to how testing will determine compliance with the permit conditions along with a copy of the permit.
 - (d) A description as to how testing will satisfy multiple requirements shall be submitted in the “Test Protocol” or in a separate correspondence.
- (3) Pre-Test Notification: The Department shall be notified in writing at least thirty (30) days prior to the date of testing to allow the Department the option of witnessing these tests.
- (4) Test Methods: Testing shall be done in accordance with Nebraska Title 129, Chapter 34 - Emission Sources; Testing; Monitoring, or using alternate test methods as approved in writing by the Department.
- (5) Final Test Report: A “Final Report” from emissions performance testing shall contain, as a minimum, the following items:
 - (a) An executive summary.
 - (b) A statement as to who is performing the stack testing along with their qualifications and experience in such areas.
 - (c) A description of the source testing conditions, including but not limited to information for each run including, actual achieved firing rate (i.e. MMBtu/hr), quantity of fuel consumed (scf), heating value of the fuel, ambient conditions, etc.

- (d) A description of the source air pollution control equipment parameters.
 - (e) Copies of all data sheets from all test runs.
 - (f) A description and explanation of any erroneous data or unusual circumstance(s) and the cause for such situation.
 - (g) A final conclusion section describing the outcome of the testing.
 - (h) A copy of the “Final Report” including test results certified by the tester, shall be provided to the Department within forty-five (45) days after the completion of the tests and within the timeframes outlined in Condition XIII.(F)(1).
- (6) Performance testing for compliance with the 12-month rolling average limit on mercury (Hg) shall be completed using an EPA-approved CEMS, or an EPA-approved continuous measurement sampling method.
- (G) Monitoring Requirements:
- (1) Continuous Emission Monitoring System (CEMS) / Continuous Opacity Monitoring System (COMS) Requirements: The permittee shall install and operate a CEMS/COMS to measure and record Opacity, inlet SO₂, outlet SO₂, NO_x, CO and CO₂ emissions from the Unit 2 boiler stack (201) and Opacity from the auxiliary boiler 2 stack (209). The monitoring system shall be used for measuring and demonstrating compliance with the appropriate Opacity, SO₂, NO_x, and CO emission limitations. CEMS/COMS availability and missing data will be handled in accordance with 40 CFR Part 60.47a(e), 60.47a(f), and 60.13 as applicable.
 - (a) The Opacity, SO₂, NO_x, CO and CO₂ monitoring system shall be installed, certified and operated according to manufacturer’s specifications and satisfy the applicable Performance Specifications in 40 CFR 60, Appendix B and the Quality Assurance/Quality Control (QA/QC) procedures in Appendix F. The Opacity, SO₂, NO_x and CO₂ monitoring systems for the Unit 2 boiler shall also meet the applicable requirements of 40 CFR 75.
 - (b) The CEMS/COMS shall meet the requirements of paragraph (G)(1)(a) prior to being used to satisfy any initial performance testing requirements.
 - (c) In keeping with 40 CFR 60.47a(c)(2), the missing data or bias adjustment procedures associated with 40 CFR 75 will not be used for the Subpart Da compliance determinations.
 - (d) Compliance with the SO₂, NO_x, and CO limits found in Table 4, and the opacity limit in Condition XIII(C)(3)(b) of this permit shall be demonstrated with the CEMS/COMS.

- (e) Alternative opacity monitoring requirements (instead of a COMS) may be utilized for the auxiliary boiler 2 stack upon written approval by EPA, in accordance with 40 CFR 60.13(i)(2).

(H) Reporting Requirements:

- (1) The NOx Compliance plan as required in Condition XIII.(D)(2) shall be submitted within 90 days after initial startup of the Unit 2 boiler. The interim status report of SCR system performance shall be submitted no later than 14 months after initial startup. The SCR Performance Report, if required, shall be submitted no later than 30 days prior to expiration of the 18 month NOx demonstration period. {Title 129, Chapter 19}
 - (2) For the purposes of reporting as required under 40 CFR 60.7, 40 CFR 60.49a, 40 CFR 60.49b, and 40 CFR 75, the permittee shall submit reports to the EPA Administrator, designated as the EPA Region VII office, per 40 CFR 60.4, and to the Department. All reports shall be postmarked by the 30th day following the end of each reporting period.
 - (a) Excess Emissions: Periods of excess emissions shall be recorded and reported quarterly in accordance with 40 CFR 60.7.
 - (b) Malfunctions: For periods during which any systems related to emissions performance either malfunction or are inoperative during boiler operation, the permittee shall maintain records of the occurrence and duration of the event. These records shall be submitted in the quarterly report, per 40 CFR 60.7(c)(3).
 - (3) Miscellaneous Correspondence: Reports, notifications, Test Protocol, and Final Report from testing shall be clearly labeled as such and mailed to the Department, and for those submittals required to be submitted to the EPA Administrator, shall be submitted also in duplicate to EPA Region VII per 40 CFR 60.4 and 40 CFR 63.9. All correspondences for this source shall reference the following NDEQ Facility Identification number: 58343, unless otherwise specified. Submittal of electronic media shall be contained on diskette or compact disk (CD) form unless otherwise superseded by other procedures in writing by the Department.
 - (4) Acid Rain Reporting: The permittee shall prepare and submit quarterly reports as required under the Acid Rain rules, 40 CFR 75, Subpart G.
- (I) Recordkeeping: Records shall be maintained on-site for a minimum period of five (5) years from the date of the record and updated no later than the 15th day of each month through the previous month. These records shall be clear and readily accessible to Department representatives and shall include the following:
- (1) NSPS Requirements: The permittee shall perform recordkeeping pursuant to 40 CFR 60.7, including, but not limited to, excess emission reports as specified in 40 CFR 60.7(c), as well as a file of other measurements, testing, etc., in accordance with 40 CFR 60.7(f).

- (2) Acid Rain Rule Requirements: The permittee shall perform recordkeeping pursuant to the Acid Rain rules under 40 CFR 75, Subpart F, including, but not limited to, calculated annual emissions of NO_x, SO₂, and CO₂, and records of opacity (COMS) readings from the Unit 2 Boiler Stack (201)
- (3) Additional Recordkeeping Requirements: The permittee shall maintain written records or computer data of the following items to show compliance with the terms and conditions of this permit:
 - (a) Fuel consumption: The daily quantity of distillate oil consumed in auxiliary boiler 2 (21-1) shall be recorded as required under 40 CFR 60.49b(d) and in accordance with 40 CFR 63.7506(a)(2).
 - (b) Fuel Supplier Certification: Certification from the fuel supplier shall be maintained to demonstrate compliance with Condition XIII.(B)(1).
 - (c) Hours of Operation: The hours of operation for the auxiliary boiler (21-1) and emergency generator (22-1) shall be recorded as 12-month rolling total on a monthly basis to demonstrate compliance with Condition XIII.(B)(1).
 - (d) Cooling Tower: Records of the vendor-guaranteed maximum total liquid drift to show compliance with Condition XIII.(B)(2). Submit a copy of guarantee to Department prior to operation.
 - (e) Quarterly Reports: A copy of quarterly reports as required by Condition XIII.(H)(2) and 40 CFR 60.7 for NSPS requirements.
 - (f) Stack Certification: A copy of the stack certification as required by Condition XIII.(C) to verify the stack information of Table 3.
 - (g) NSPS Notifications: A copy of the written notifications as required by Condition XIII.(E).
 - (h) Startups, Shutdowns, and Malfunctions: Records of the startup, shutdown, and malfunction periods in accordance with 40 CFR 60.7(b) and Chapter 35.
- (4) Inspection and maintenance records for each baghouse, to show compliance with Conditions XIII.(B)(3) and (B)(4), shall include the following:
 - (a) Records documenting when routine observations were performed with a description including pressure differential readings, visual emission observations, and any atypical observations.
 - (b) Records documenting when routine maintenance and preventive actions were performed with a description of the maintenance and/or preventive action performed.
 - (c) Filter replacement records including filter position, type, and date of filter installation.

- (d) Records documenting equipment or bag failures, malfunctions, or other variations, including time of occurrence, remedial action taken, and when corrections were made.
- (J) Acid Rain Requirements: The permittee shall comply with the applicable provisions of the Acid Rain Program of Title IV of the Clean Air Act. {Title 129, Chapter 26}
- (K) The existing auxiliary boiler 1 (emission ID 2-1) shall be permanently decommissioned upon startup of the NCS Unit 2 main boiler. {Title 129, Chapters 4 and 19}

Pursuant to a Delegation Memorandum dated May 3, 2000, and signed by the Director, the undersigned hereby executes this document on behalf of the Director.

March 9, 2005

Date

Shelley Kaderly, Air Administrator
Air Quality Division

FACT SHEET

OPPD-Nebraska City Station
7264 L Road
Nebraska City, Nebraska 68410

March 9, 2005

DESCRIPTION OF THE FACILITY OR ACTIVITY:

Omaha Public Power District (OPPD) currently operates the Nebraska City Station (NCS) with an existing nominal 650 megawatt (MW) coal-fired electric generating unit (Unit 1) located approximately 5 miles southeast of Nebraska City, Nebraska. This original generation facility is currently a major source of air emissions under both the Prevention of Significant Deterioration (PSD) program and the Title V operating permit program. Its Standard Industrial Classification (SIC) code is 4911, and the North American Industry Classification System (NAICS) code is 221112 for fossil fueled electric generators. NCS was issued a Title V (Class I) operating permit on 04/28/2004 for the operation of Unit 1.

The Department received a PSD Construction Permit application for "NCS Unit 2" on 2/23/2004. The proposed modification at NCS will consist of the addition of one (1) nominal 660 MW (net) coal-fired electric generating unit (Unit 2) with a maximum rated heat input of 6,478 MMBtu/hr. The unit is classified as a pulverized coal (PC) dry-bottom boiler and will primarily combust western subbituminous coal from the Powder River Basin (PRB) with a minimum heat content of approximately 8,350 Btu/lb. This is the same coal as currently being used in Unit 1. Distillate fuel oil will be used as a start-up fuel.

Other proposed modifications identified in the permit application consist of the modification or addition of the following support equipment: extending the existing coal conveying and tripper system (emission points 105 and 106, equipment IDs 9-1 and 9-2) to serve Unit 2, a cooling tower (18-cell), storage silos for lime (reagent in spray-dryer absorber, or SDA), recycled ash (partially spent reagent), fly ash, and mercury control sorbent, a 125 MMBtu/hr auxiliary boiler (Aux Boiler 2), and a 1,837-horsepower diesel-fired emergency generator. The auxiliary boiler will be operated only when both Unit 1 and Unit 2 main boilers are inoperative, and it will be used to provide building heat and the steam needed for startup of the main boilers. The emergency generator will be used for emergency shut down of the plant equipment. Additionally, the emergency generator will be operated approximately once per week for about one hour in order to maintain it in working order. The auxiliary boiler and emergency generator each have a proposed limit on operating hours of 500 hours per year.

Some of the existing facilities (emission sources) serving Unit 1 will see an increase in utilization due to the operation of Unit 2. These include the existing coal pile, haul roads, the crusher house (emission points 109 and 110, equipment IDs 8-1 and 8-2), and the transfer house (111, 7-1). OPPD also proposes to add emission limitations for the crusher house dust collectors, require dust collector usage on other existing emission points, and require decommissioning of the existing auxiliary boiler 1 upon startup of Unit 2 in order to ensure compliance with relevant ambient air quality standards and allowable increment concentrations.

TYPE AND QUANTITY OF AIR CONTAMINANT EMISSIONS ANTICIPATED:

Unit 2 will have the potential to emit nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM), PM with an aerodynamic diameter less than or equal to 10 micrometers (PM₁₀), sulfur dioxide (SO₂), sulfuric acid mist (H₂SO₄), volatile organic compounds (VOCs), fluorides (expressed as hydrogen fluoride, HF) and hazardous air pollutants (HAP). New ancillary equipment (auxiliary boiler, emergency generator) at NCS will have the potential to emit NO_x, CO, PM/PM₁₀, SO₂, VOCs and HAPs.

Annual potential to emit calculations for the ancillary equipment are based on the proposed operational limit of 500 hours per year. Annual potential to emit calculations for Unit 2 are representative of 100 percent load firing conditions. As utility boilers are primarily used for base-load electrical generators, potential emissions were calculated based on full-time operation of 8,760 hours per year. Table 1 shows a summary of the potential increase in annual emissions for this proposed project under the terms of this permit. Increased emissions from existing equipment (all 100-series emission points) are a result of increased coal handling to accommodate Unit 2. Attachment A details the emission factors and calculations for each individual emissions point.

Table 1 - Emissions Summary

Emission Point	Unit Description	POTENTIAL ANNUAL EMISSIONS INCREASE (tons/yr)								
		NO _x ^[1]	SO ₂	CO	VOC	PM	PM ₁₀	H ₂ SO ₄ mist	Fluorides (as HF)	Total HAPs ^[2]
<i>Existing Equipment</i>										
105	Coal Tripper System					6.76	6.76			
106	Coal Tripper System					6.76	6.76			
109	Coal Crusher House					5.27	5.27			
110	Coal Crusher House					5.27	5.27			
111	Coal Transfer House					1.88	1.88			
<i>New Unit 2 Equipment</i>										
201	Unit #2 Boiler	1,986	2,695	4,540	96.5	510.7	510.7	119.2	11.3	55.4
202	SDA Lime Storage	-	-	-	-	0.75	0.75	-	-	-
203	Recycle Ash Storage	-	-	-	-	1.45	1.45	-	-	-
204	Fly Ash Waste	-	-	-	-	1.45	1.45	-	-	-
207	Emer. Gen	10.3	0.2	2.7	0.3	0.22	0.18	negl.	negl.	0.014
208	Cooling Tower	-	-	-	-	12.9	5.8	-	-	-
209	Auxiliary Boiler	5.3	1.8	1.1	0.2	0.7	0.7	0.06	negl.	0.01
211	Fly Ash Exhauster	-	-	-	-	0.75	0.75	-	-	-
	Haul Roads	-	-	-	-	38.7	8.3	-	-	-
	Coal Pile	-	-	-	-	1.24	0.62	-	-	-
	Ash Pile	-	-	-	-	11.8	5.9	-	-	-
	Material Handling	-	-	-	-	2.32	1.10	-	-	-
Totals:		2,002	2,697	4,544	96.9	583.1	537.7	119.2	11.3	55.4

^[1] During the first 18-months of operation, potential emissions of NO_x from Unit #2 are 3,405 tpy based on 0.12 lb/mmBtu emission limit.

^[2] Total HAP emissions includes HF, which is also shown separately in this table, because HF is a PSD regulated pollutant.

APPLICABLE REQUIREMENTS AND VARIANCES OR ALTERNATIVES TO REQUIRED STANDARDS:

A. Prevention of Significant Deterioration (PSD):

The existing NCS facility is classified as a major stationary source under the PSD program (>100 tpy). As a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr heat input, NCS is included as one

of the 28 listed source categories in 40 CFR 52.21(b)(1)(iii) that must include fugitive emissions in determining whether a proposed modification is major. PSD regulations require that all new or modified major stationary sources submit a BACT analysis and ambient air quality analysis for all criteria and other pollutants emitted over the significant emission increase thresholds listed in 40 CFR 52.21(b)(23). An 'Additional Impact Analysis' must also be conducted as required in 40 CFR 52.21(o).

Because the existing Unit 1 boiler process capacities will not be affected by the Unit 2 addition, emissions from Unit 1 are not included in the emissions increase analysis. Refer to Table 2 for Significant Thresholds and PSD review applicability.

Table 2 - Estimated Potential Emissions vs. PSD Thresholds

Regulated Pollutant	Maximum Annual Emissions (ton/yr)	PSD Significance Threshold (ton/yr)	PSD/BACT Applicability
NO _x	2,002	40	Yes
SO ₂	2,697	40	Yes
CO	4,544	100	Yes
PM	583	25	Yes
PM ₁₀	538	15	Yes
VOC	97	40	Yes
Lead (Pb)	0.12	0.6	No
H ₂ SO ₄ mist	119	7	Yes
Fluorides (calculated as HF)	11.3	3	Yes

1.00 Best Available Control Technology (BACT):

Emission estimates in Table 2 indicate that NCS Unit 2 will have the potential to emit NO_x, SO₂, CO, PM/PM₁₀, VOC, H₂SO₄ mist, and fluorides in excess of PSD significance thresholds, thus requiring the applicant to apply BACT for each new or modified emissions unit that has the potential to emit these pollutants. BACT is defined as an emission limitation established based on the maximum degree of pollutant reduction, determined on a case-by-case basis, considering technical, economic, energy, and environmental factors. However, BACT cannot be less stringent than emission limits established by an applicable NSPS. Table 3 summarizes BACT for the Unit 2 boiler. Because of the low limit proposed on hours of operation (500) for the ancillary equipment (auxiliary boiler 2 and the emergency generator), BACT for these units is considered good combustion and the use of clean fuels, and were not considered further as part of the BACT analysis for NCS Unit 2.

Table 3 - Proposed Unit 2 Boiler BACT Emission Limitations.

Pollutant	Emission Limit	Control Type
SO ₂	0.095 lb/MMBtu (30-day rolling average)	Dry FGD & Fabric Filter
NO _x	0.07 lb/MMBtu (30-day rolling average)	SCR
CO	0.16 lb/MMBtu (test method average)	Combustion Controls
PM/PM ₁₀	0.018 lb/MMBtu (test method average)	Fabric Filter
VOC	0.0034 lb/MMBtu (test method average)	Combustion Controls
H ₂ SO ₄ mist	0.0042 lb/MMBtu (test method average)	Dry FGD & Fabric Filter
HF	0.0004 lb/MMBtu (test method average)	Dry FGD & Fabric Filter

This Fact Sheet contains a summary of the BACT analysis performed for this permitting activity. Refer to the permit application for complete details including the basis for the cost calculations provided in this permit document.

1.01 Top-Down BACT Analysis

The first step in a top-down BACT analysis is to determine, for the pollutant in question, the most stringent control technology and emission limit available for a similar source or source category. These technologies represent the top control alternative under the BACT analysis. If it can be shown that this level of control is infeasible on the basis of technical, economic, energy, and environmental impacts for the source in question, then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy or environmental consideration.

A “Top-Down” BACT analysis basically consists of the following steps:

- *Identify All Control Technologies.* All control technologies for similar processes, as well as Lowest Achievable Emission Rate (LAER) technologies are included.
- *Eliminate Technically Infeasible Options.* Technologies demonstrated to be infeasible based on physical, chemical, and engineering principles are excluded from further consideration.
- *Rank Technologies By Control Effectiveness.* Technically feasible control technologies are ranked in the order of highest expected emission reduction to lowest expected emission reduction. The ranking also includes expected emission rate, control effectiveness, energy impacts, environmental impacts (including toxic and hazardous air emissions), and economic impacts.
- *Control Technology Evaluation.* The technology ranking is evaluated and case-by-case consideration is given to energy, environmental, and economic impacts. The most effective option not rejected is chosen as BACT and is used to express an enforceable emission limitation for the affected emission unit.

1.02 Applicable Pollutants

The Unit 2 BACT analysis addresses pollutant emissions of SO₂ (and related emissions of H₂SO₄ mist), NO_x, CO, PM/PM₁₀, VOC, and fluorides. Particulate matter limitations for utility boilers are generally

expressed as total PM. PM₁₀ is a subset of PM, and therefore cannot exceed PM. In order to present a conservative analysis, the two components of particulate matter (PM/PM₁₀) are treated together and considered equal for the purpose of this analysis. The BACT analysis has been divided into sections that address each applicable pollutant individually.

1.10 SO₂ BACT Analysis / H₂SO₄ BACT Analysis

The objective of this analysis is to determine BACT for SO₂ and related emissions of H₂SO₄ from the proposed Unit 2 boiler. Generally, there are two approaches to controlling SO₂ emissions: removal of elemental sulfur from the fuel prior to combustion, and flue gas desulfurization (FGD), which consists of removal of SO₂ from the flue gases after combustion. Although this analysis focuses primarily on SO₂ emissions, this analysis is applicable to emissions of H₂SO₄ (sulfuric acid mist).

SO₂ Formation. SO₂ emissions are formed from the oxidation of organic and pyritic sulfur in the coal during the combustion process. The majority of sulfur is oxidized to SO₂, however a small quantity is further oxidized to form sulfur trioxide (SO₃). Selective catalytic reduction (SCR) technology for control of nitrogen oxide emissions (see section 1.21) can increase the amount of SO₂ oxidized to SO₃. The extent of this oxidation depends on the catalyst formulation and SCR operating conditions.

Approximately 90% of the sulfur present in the subbituminous coal will be emitted as SO_x compounds. Alkaline ash from some coals (including PRB coals) may cause some of the sulfur to react in the furnace to form various sulfate salts that are then retained in the fly ash. H₂SO₄ mist forms when SO₃ reacts with moisture in the flue gas and in the environment.

In solid fuels, such as coal, a significant fraction of the sulfur is in the form of pyrite (FeS₂) or some other mineral sulfates. Mineral sulfates can be removed through washing or other physical cleaning. However, organic sulfur cannot be removed by physical cleaning. Because coal is solid, the use of chemical desulfurization processes can be very costly. Additionally, it is unlikely that sufficient desulfurization of coal can be accomplished to meet current SO₂ emission requirements. Therefore, some form of FGD must be considered for solid fuels.

1.11 Identification of SO₂ Control Technologies

The following paragraphs identify available FGD technologies for coal-fired boiler processes and address the feasibility of the technologies as applied to the operation of the proposed Unit 2 Boiler. FGD technologies can be divided into two main categories, regenerative and throwaway processes. Regenerative processes recover sulfur in a usable form that can be sold as a reusable sulfur product. Throwaway processes remove sulfur from the flue gas and the scrubber byproducts are discarded. All of the FGD technologies considered can achieve SO₂ removal efficiencies of 90 to 95%, depending on the amount of sulfur in the coal. For relatively high sulfur coals, removal efficiencies can exceed 95%, while for lower sulfur coals (such as PRB), the achievable removal efficiency is less than 95%.

Regenerative processes, by nature, contain a regeneration step in the FGD process that results in higher costs than throwaway processes due to equipment and operational expenses. However, in instances where disposal options are limited and markets for recovered sulfur products are readily available, regenerative processes may be used. Potential regenerative processes that are available include the Wellman-Lord (W-L) process, magnesium oxide process, citrate scrubbing process, Flakt-Boliden process, aqueous carbonate process, Sulf-X process, Conosox process, Westvaco process and adsorption of SO₂ by a bed of copper oxide.

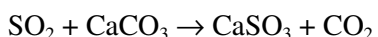
A new regenerative process that was developed as an indirect result of collaborative research with the former U.S. Bureau of Mines and the University of Minnesota is the Pahlman process. The Pahlman process is a dry removal technology that can remove multiple pollutants (NO_x and SO₂) at efficiencies greater than 99 percent. As a regenerative process, the Pahlman process purportedly reduces problems associated with waste disposal and creates a commercially valuable byproduct. In the closed-loop process, the Phalmanite sorbent repeatedly captures NO_x and SO₂, which upon regeneration, yields raw sulfates and nitrates. The Pahlman process is new technology that has been pilot tested at several industrial sites, including smaller coal-fired electrical generating plants. However, proven technical feasibility with application to large-scale coal-fired electrical generating units, such as the proposed Unit 2 Boiler, has yet to be demonstrated. Therefore, this new regenerative technology will not be considered further in this BACT analysis.

Throwaway processes such as limestone scrubbing have become widely accepted by the coal-fired power industry for FGD because limestone scrubbers have lower overall costs and are simpler to operate than regenerative processes. Because the throwaway processes can achieve the same removal efficiencies as regenerative processes and cost less, this BACT analysis for SO₂ will focus on throwaway processes and further discussion of regenerative process will not be considered.

Throwaway processes can be divided into two categories, wet and dry. Wet or dry refers to the state of the waste by-products. Both wet and dry technologies have advantages and disadvantages with respect to initial capital and operational expenses.

Wet FGD

Wet scrubbing (wet FGD) systems used for SO₂ reduction typically consist of the following operations: scrubbing or absorption, lime handling and slurry preparation, sludge processing, and flue gas handling. Wet FGD technology is a well-established process for removing SO₂ from flue gas. In wet scrubbers, the flue gas enters the spray tower or absorber where it is sprayed with a water slurry which is approximately 10 percent lime or limestone. Sodium alkali solutions can also be used in FGD systems, however these processes are considerably more expensive than lime. The preferred sorbents are limestone and lime, respectively, due to the availability and relatively low cost of limestone. The calcium in the slurry reacts with the SO₂ in the flue gas to form calcium sulfite (CaSO₃) or to a lesser extent, calcium sulfate (CaSO₄). The overall chemical reaction can be simply expressed as:



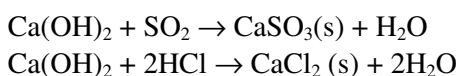
Spent slurry from the reaction tank is pumped into a thickener where solids settle before being filtered for final dewatering to approximately 50% solids. Water removed during this process is sent to a process water holding tank, which eventually will require wastewater treatment. In a non-regenerative system, the waste sludge must also be disposed of properly. Finally, scrubbed flue gases are directed through a stack gas reheater in order to minimize corrosion downstream of the scrubber due to conversion of SO₂ to SO₃ and subsequently, sulfuric acid (H₂SO₄). Reheating is sometimes needed for proper drafting and rise of exhaust gases out the stack, as well as minimizing condensate. As an alternative, the stack can be constructed of acid resistant material.

Most wet FGD systems have two stages, one for fly ash removal and one for SO₂ removal. The flue gas normally passes first through a fly ash removal device, either an electrostatic precipitator (ESP) or a bag filter, and then into the SO₂ absorber. There are many different types of absorbers that can be used in wet FGD systems, including: spray towers, venturis, plate towers, and mobile packed beds. However,

many of these systems can result in scale buildup, plugging or erosion, which can affect the dependability and efficiency of the absorber. Therefore, simple scrubbers such as spray towers are commonly used. The chief drawback of the spray tower design is that it requires a higher liquid-to-gas ratio for equivalent removal of SO₂ to other absorber designs.

Dry FGD

In contrast to wet scrubbing systems, dry FGD systems (spray dryer) systems use much smaller amounts of liquid. With a spray dryer absorber system, the flue gases enter an absorbing tower (dryer) where the hot gases are contacted with a finely atomized slurry, which is usually a calcium-based sorbent such as calcium hydroxide or calcium oxide (lime). Acid gases and SO₂ are absorbed by the slurry mixture and react to form solid salts. The absorption process is temperature dependent and the cooler the flue gas, the more effectively the acid gases will react with the sorbents. The overall chemical reactions can be simply expressed as:



As can be seen above, one mole of calcium hydroxide will neutralize one mole of SO₂, whereas one mole of calcium hydroxide will neutralize two moles of hydrochloric acid (HCl). A similar reaction occurs with the neutralization of hydrofluoric acid (HF). These reactions demonstrate that when using a spray dryer the HCl and HF are removed more readily than SO₂. Reagent requirements should consider that the HCl and HF are removed first, followed by the reagent quantity required to remove the SO₂¹.

The heat of the flue gas evaporates the water droplets in the sprayed slurry, and a non-saturated flue gas exits the absorber tower. The exhaust stream exiting the absorber contains fly ash, calcium salts, and unreacted lime, which must be sent to a particulate control device such as an electrostatic precipitator (ESP) or fabric filter (baghouse). The particulate control device not only is necessary to control particulate matter, but also aids in acid-gas removal. Acid gases are removed when the flue gas comes in contact with the lime-containing particles on the surface of the ESP or baghouse. Fabric filters are considered to have slightly higher residual acid gas removal levels than ESPs because the acid gases must pass through the lime-containing filter cake in a fabric filter system. Modern dry FGD systems include a loop to recycle a portion of the baghouse-collected material for re-use in the FGD module because this material contains a relatively high amount of unreacted lime.

1.12 Top-Down Ranking

The SO₂ control technologies that are considered technically feasible for implementation on Unit 2 have been ranked from most to least effective in terms of emission reduction potential. Table 4 summarizes the control technology ranking.

Table 4 - SO₂ Control Technology Summary & Top-Down Ranking

Identified Control Technology	Potential to control SO₂ emissions	Available and demonstrated effective^a	In service on similar systems	Technically feasible for Unit 2	% SO₂ Reduction
Wet FGD	Yes	Yes	Yes	Yes	>90%
Dry FGD	Yes	Yes	Yes	Yes	>90%

^a Based on design and configuration of the Unit 2 Boiler.

¹ Karl B. Schnelle, Jr. and Charles A. Brown, Air Pollution Control Technology Handbook, CRC Press, 2002.

1.13 Control Technology Evaluation

The following paragraphs present detailed evaluations of each of the feasible SO₂ control technologies. Energy, environmental and economic impacts are considered for each of the potential control technologies.

Wet FGD

As stated previously, wet FGD is a process where the flue gas from the boiler is passed through an absorber, which uses alkaline slurry to remove the SO₂ from the exhaust gas stream. There are numerous operating parameters that can affect the SO₂ removal rate of the absorber. Those parameters are: liquid-to-gas ratio, pH, gas velocity, residence time, gas distribution, scrubber design, turndown, and coal properties such as heating value, moisture content, sulfur content, ash content, and chlorine content. Another design consideration with wet FGD systems is that the flue gas exiting the absorber is saturated with water and does still contain some SO₂. These gases are highly corrosive to any downstream equipment. To minimize corrosion of the downstream equipment, the gases can be reheated to temperatures above the dewpoint, or construction materials and design conditions can be selected to withstand the corrosive conditions. Both of these alternatives increase the cost of an FGD system. Reheaters can also experience operational problems ranging from acid attack on reheater components to vibration, which causes structural deterioration.

Another potential problem with wet FGD systems using lime or limestone is that calcium sulfite in the sludge settles and filters poorly. This problem can be remedied using a forced oxidation system in a designated section of the absorber or in a separate oxidation tank. This process creates calcium sulfate, which is easily filtered. The forced oxidation process also helps to prevent scale buildup by removing calcium sulfites through conversion to calcium sulfate, thus preventing calcium sulfites from oxidizing and precipitating out in the scrubber internal areas. Scaling and oxidation can also be reduced through the use chemical inhibitors such as magnesium and dibasic acid. The necessary reduction of scaling in wet FGD equipment increases the operational cost for these systems.

Non-regenerable wet FGD processes produce a sludge waste, which must be disposed of properly. In these processes, the scrubbing liquid can be recycled or regenerated, but no useful product is obtained from the sludge. Additionally, wastewater treatment is required for the process wastewater produced by wet FGD systems.

Energy: Use of Wet FGD to control SO₂ emissions from Unit 2 will result in significant energy penalties to facility operations in the form of the electricity demand required for operation of ancillary equipment as well as additional backpressure on the exhaust system that results in a slight reduction in output. Pumps and water handling equipment required for slurry preparation, as well as flue gas reheating, would consume approximately 1.25% of the total proposed capacity of Unit 2.

Environmental: The primary detrimental environmental effect of the Wet FGD system is the creation of waste byproducts from the spent slurry. Dewatering of the spent slurry results in the production of a wastewater stream as well as a waste sludge that must be disposed of in a landfill.

Economic: The capital investment associated with the installation of a Wet FGD system and associated fabric filter for Unit 2 to achieve an SO₂ emission level of 0.095 lb/MMBtu during combustion of subbituminous coal is estimated at \$80,672,300. Costs were based on budgetary quotations and standard

engineering estimating practices presented in the EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002. Refer to the permit application for additional cost analysis details.

The total annual cost to maintain a 0.095 lb/MMBtu SO₂ emission level for Unit 2 using a Wet FGD/Fabric Filter control system is estimated to be \$18,925,400. This annual cost results in a cost effectiveness for SO₂ removed of \$604/ton when combusting subbituminous coal (See Table 5). Note that this cost does not include wastewater treatment costs, which would make the annualized \$/ton cost of Wet FGD somewhat higher than this.

Dry FGD

In a Dry FGD system, also called a spray dryer absorber (SDA), flue gases are passed through an atomized spray of alkaline slurry. The minimal amount of moisture in the slurry is dried by the exhaust gases, which leave the absorber and are directed to a baghouse or ESP for particulate control.

Key design parameters for spray dryer design are flue gas flow rate and composition, temperature of the flue gas, alkaline stoichiometric ratio, alkaline properties, and the required removal efficiency. The most important parameter for sizing a spray dryer is to ensure adequate residence time in the absorber to prevent wet solids at the spray dryer outlet.

SDAs are relatively simple devices with few moving parts, and thus are not prone to a lot of operational problems. The primary maintenance problem associated with spray dryers is potential plugging in the solid or slurry transport systems. However, if manufacturer suggested maintenance and inspection schedules are followed, these problems can be minimized or avoided.

Wastewater treatment is not required with a SDA system, because the water is completely evaporated in the absorber. However, a solid waste stream is created from the fabric filter baghouse. This waste can be recycled with an optional recycling system, but is more often shipped for proper disposal. Because this waste is high in lime and contains sulfur, a necessary agricultural soil supplement, there is a possibility of beneficial re-use of this by-product by farmers.

Estimated SO₂ emission rates for implementation of a Dry FGD system on Unit 2 are listed in Table 4. The emission rates incorporate the use of Dry FGD to control SO₂ emissions to 0.095 lb/MMBtu, which is approximately equivalent to 90 percent control. The NSPS for utility boilers such as the one proposed for Unit 2 requires only 70 percent control.

Energy: Use of Dry FGD to control SO₂ emissions from Unit 2 will result in energy penalties to facility operations in the form of the electricity demand required for operation of ancillary equipment such as the reagent preparation and atomizer equipment as well as additional backpressure on the exhaust system that results in a slight reduction in output. The additional electrical demand will consume approximately 1% of the total proposed capacity of Unit 2 according to design estimates.

Environmental: The primary detrimental environmental effect of the Dry FGD system is the creation of a solid waste byproduct from the spent reagent. Unlike Wet FGD, there is no wastewater stream resultant from the use of Dry FGD. The solid waste that is produced can be land filled or possibly used as an agricultural soil supplement.

Economic: The capital investment associated with the installation of a Dry FGD system and associated fabric filter for Unit 2 to achieve a SO₂ emission level of 0.095 lb/MMBtu during combustion of subbituminous coal is estimated at \$49,924,800. Costs were based on budgetary quotations and standard

engineering estimating practices presented in the EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

The total annual cost to maintain a 0.095 lb/MMBtu SO₂ emission level for Unit 2 using a Dry FGD/Fabric Filter control system is estimated to be \$14,685,700. This annual cost results in a cost effectiveness for SO₂ removed of \$468/ton when combusting subbituminous coal (See Table 5).

Table 5 - Summary of Emission Rates & Top-Down SO₂ BACT Analysis Costs

Emission Unit	Control Alternative	Emission Rate (Lb/MMBtu)	Emissions (lb/hr) tpy	Emissions Reduction tpy	Total Annualized Cost \$/yr	Total Cost Effectiveness \$/ton
Unit 2	Uncontrolled	1.2	(7,774) 34,048	-	-	-
Unit 2	Wet FGD	0.095	(615) 2,695	31,353	18,925,300	604
Unit 2	Dry FGD	0.095	(615) 2,837	31,353	14,685,700	468

1.14 Proposed SO₂ & H₂SO₄ BACT Selection

Because the Wet FGD and Dry FGD can produce an equivalent level of SO₂ control for this application, and because Dry FGD has a lower annualized cost than Wet FDG, OPPD proposes to use Dry FGD as BACT for SO₂ emissions from the Unit 2 boiler. Also, Dry FGD has an environmental advantage over Wet FGD in that Dry FGD does not consume as much water and does not produce a wet waste product/slurry. OPPD also proposes the SDA system and fabric filter as BACT for control of H₂SO₄ emissions, which is considered to be the most effective control and emissions are expected to be reduced by approximately 95% using the proposed control system. The proposed BACT emission limit for H₂SO₄ emissions is 0.0042 lb/MMBtu, which is the same as that permitted for the Council Bluffs Energy Center Unit 4 boiler. Table 3 lists the SO₂ and H₂SO₄ emission limitations proposed as BACT under typical operating ranges for the Unit 2 Boiler.

For short-term periods of spray dryer absorber (SDA) maintenance, higher SO₂ emissions limits are needed to allow for changeout of the SDA atomizer every 3-4 months. The atomizer changeout can be done in a matter of hours, and in normal circumstances, is not expected to affect the ability of the unit to meet the above BACT limit on a 30-day rolling average basis. However, to allow for the higher SO₂ emissions during atomizer changeout, the dispersion modeling for short term (3-hour and 24-hour) averaging periods has been done using higher SO₂ emission rates to account for only partial control during atomizer changeout. Because the system will have two separate SDA modules, only one of these will normally be out of service during atomizer changeout, which is expected to take 4 hours or less. The in-service SDA module will be designed to remove 60% of all SO₂ when the other module is off-line. Thus, the proposed 3-hour maximum emission rates are based on 60% control, and 24-hour maximum emissions are based on 60% control for 4 hours and full control for the other 20 hours. Therefore, OPPD requests 3-hour and 24-hour average, modeling-based SO₂ limits of 0.48 lb/MMBtu (60% control from 1.2 lb/MMBtu), and 0.163 lb/MMBtu, respectively.

1.15 BACT Selection Review For SO₂ & H₂SO₄

Information concerning recently proposed or permitted coal-fired power projects was obtained from EPA's Clean Air Technology Center (CATC) website, where a list of nationwide coal-fired power projects has been compiled and is available for downloading at

<http://www.epa.gov/ttn/catc/dir1/natlcoal.xls>. Additional information was obtained through EPA's RACT/BACT/LAER Clearinghouse (RBLC) database. The list of comparable, permitted or proposed, coal-fired facilities is presented in tabular form in Appendix D of the permit application. This information provides a comparison of actual or proposed BACT limits at other facilities with the proposed BACT limits for Unit 2. The proposed 0.095 lb/MMBtu SO₂ limit and 0.0042 lb/MMBtu H₂SO₄ limit for Unit 2 is equal to or lower than other recently permitted facilities such as the nearby Council Bluffs Energy Center Unit 4 in Iowa, which also has a limit of 0.10 lb/MMBtu & 0.0042 lb/MMBtu.

1.20 NO_x BACT Analysis

The objective of this analysis is to determine BACT for NO_x emissions from the proposed Unit 2 Boiler. Control of NO_x emissions from boilers can be attained through either the application of combustion controls or flue gas treatment (post-combustion) technologies. Combustion control processes can reduce the quantity of NO_x formed during the combustion process. Post-combustion technologies reduce the NO_x emissions in the flue gas stream after the NO_x has been formed in the combustion process. These methods may be used alone or in combination to achieve the various degrees of NO_x emissions required.

NO_x Formation. There are two primary mechanisms of NO_x formation in utility boilers that combust coal; thermal production of NO_x from atmospheric nitrogen and oxygen, and oxidation of nitrogen bound in the fuel. High combustion temperatures cause the nitrogen (N₂) and oxygen (O₂) molecules in the combustion air to react and form NO_x. Because the thermal NO_x production is primarily a function of combustion temperature, NO_x emission rates vary greatly with burner design. Experimental measurements of thermal NO_x formation have shown that the NO_x concentration is exponentially dependent on temperature and is proportional to nitrogen concentration in the flame, the square root of oxygen concentration in the flame, and the gas residence time. The formation of fuel NO_x from reactions of fuel bound nitrogen and air, can account for up to 80 percent of total NO_x from coal combustion. Subbituminous coals contain from 0.5 to 2 percent by weight fuel-bound nitrogen.

1.21 Identification of NO_x Control Technologies

The following paragraphs identify potentially available control technologies for coal-fired boiler processes and address the feasibility of the technologies as applied to the operation of the proposed Unit 2 Boiler.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) systems are an add-on flue gas treatment (post-combustion control technology) to control NO_x emissions. The SCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH₃) or urea to reduce the NO_x in the flue gas to N₂ and H₂O. The reagent is injected into the flue gas prior to passage through a catalyst bed, which accelerates the NO_x reduction reaction rate. Use of SCR results in small levels of NH₃ emissions (NH₃ slip). As the catalyst degrades, NH₃ slip will increase, ultimately requiring catalyst replacement.

Many types of catalysts, ranging from active metals to highly porous ceramics, are available for different applications. The type of catalyst chosen depends on several operational parameters, such as reaction temperature range, flue gas flow rate, fuel source, catalyst activity and selectivity, operating life, and cost. Catalyst materials include, platinum (Pt), vanadium (V), titanium (Ti), tungsten (W), titanium oxide (TiO₂), zirconium oxide (ZrO₂), vanadium pentoxide (V₂O₅), silicon oxide (SiO₂), and zeolites (crystalline alumina silicates).

SCR systems can utilize aqueous NH₃, anhydrous NH₃, or a urea solution to produce NH₃ on demand. Aqueous NH₃ is generally transported and stored in concentrations ranging from 19 to 30% and therefore requires more storage capacity than anhydrous NH₃. Anhydrous NH₃ is nearly 100% pure in concentration and is a gas at normal atmospheric temperature and pressure. Anhydrous NH₃ must be stored and transported under pressure and when stored in quantities greater than 10,000 pounds, is subject to Risk Management Planning (RMP) requirements (40 CFR 68). The urea solution (urea and water at approximately 32% concentration) is used to form NH₃ on demand for injection into the flue gas. Generally, a specifically designed duct and decomposition chamber with a small supplemental burner is used to provide an appropriate temperature window and residence time to decompose urea to NH₃ and isocyanic acid (HNCO). Application of urea-based SCR systems to utility boilers is a relatively new practice that is still under development.

Several different SCR system configurations have been used on utility boilers. In a high-dust SCR system, the reactor is located downstream of the economizer and upstream of the air heater, FGD system, and particulate control device. Low-dust SCR systems locate the reactor downstream of a particulate control device where the flue gas is relatively dust-free. Tail-end SCR systems locate the reactor downstream from all air pollution control equipment where most flue gas constituents detrimental to the SCR catalyst have been removed. However, tail-end SCR systems can require reheating of the flue gas to minimize condensation, leading to corrosion problems.

SCR is a proven technology that has been in commercial use on utility boilers since the late 1970s. Therefore, SCR is considered a feasible NO_x control technology and will be considered further in this BACT analysis.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is another method of post-combustion control. Similar to SCR, the SNCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH₃) or urea to reduce the NO_x in the flue gas to N₂ and H₂O. However, the SNCR process works without the use of a catalyst. Instead, the SNCR process occurs within a combustion unit, which acts as the reaction chamber. The heat from the boiler combustion process provides the energy for the NO_x reduction reaction. Flue gas temperatures in the range of 1,500 to 1,900 °F, along with adequate reaction time within this temperature range, are required for this technology. SNCR is currently being used for NO_x emission control on industrial and utility boilers, and can achieve NO_x reduction efficiencies of up to 75%, however in typical applications SNCR provides 30% to 50% NO_x reduction. SNCR is a proven technology that has been in commercial use on utility boilers, and therefore, is considered a feasible NO_x control technology and will be considered further in this BACT analysis.

Combustion Controls

Combustion controls such as flue gas recirculation (FGR), reducing air preheat temperature (RAP), oxygen trim (OT), low excess air (LEA), staged combustion air (SCA), and low NO_x burners (LNB), can be used to reduce NO_x emissions depending on the type of boiler, characteristics of fuel and method of firing. In practice, combustion controls have not provided the same degree of NO_x controls as provided by add-on post combustion control technologies, but are generally used in conjunction with add-on controls (such as SCNR) to increase the NO_x removal efficiency. New developments in LNB technologies have demonstrated substantial reductions in NO_x formation, however only limited data are available that demonstrate control potential approaching that of SCR systems. Combustion controls have

been in commercial use on industrial and utility boilers and are considered a feasible NO_x control technology.

1.22 Top-Down Ranking

The NO_x control technologies that are considered technically feasible for implementation on Unit 2 have been ranked from most to least effective in terms of emission reduction potential. Table 6 summarizes the control technology and ranking.

Table 6 – NO_x Control Technology Summary & Top-Down Ranking

Identified Control Technology	Potential to control NO_x emissions	Available and demonstrated effective^a	In service on similar systems	Technically feasible for Unit 2	% NO_x Reduction
SCR	Yes	Yes	Yes	Yes	up to 90%
SNCR	Yes	Yes	Yes	Yes	30-75%
Combustion Controls	Yes	Yes	Yes	Yes	30-50% ^b

^a Based on design and configuration of the Unit 2 Boiler.

^b Estimated control efficiency depends greatly on uncontrolled NO_x level and boiler design.

1.23 Proposed NO_x BACT Selection

The proposed NO_x BACT for Unit 2 is the use of SCR as a post-combustion technology to control NO_x emissions. Based on the above top-down ranking of control technologies, SCR provides the highest level of NO_x control and is therefore considered the “top” control technology. Because OPPD proposes to use the most effective NO_x control technology for the Unit 2 boiler, a cost analysis and further technology review has not been included in the BACT analysis. Table 3 lists the NO_x emission limitations proposed as BACT under typical operating ranges for the Unit 2 boiler. The emission limit of 0.07 lb/MMBtu is an aggressive limit based on the expected performance of an SCR system on a similar type and size of utility boiler burning coal. Therefore, during the first 18 months following initial startup of Unit 2, the emission limit shall be 0.12 lb/MMBtu utilizing SCR. If, with good faith efforts in the operation of the installed NO_x control equipment, and sufficient demonstration that other steam generating units of similar size and control equipment burning PRB subbituminous coal are unable to achieve the 0.07 lb/MMBtu emission rate, then the proposed BACT limit shall be subject to revision in coordination with the Department and EPA.

1.24 BACT Selection Review for NO_x

As described in Section 1.15, information concerning recently proposed or permitted coal-fired power projects was compared to show that the proposed NO_x BACT limit of 0.07 lb/MMBtu is consistent with the lowest NO_x level proposed and permitted at other facilities. Recent EPA Region VII permits of utility boilers burning PRB coal have contained conditions to allow the sources to operate up to 36 months (Hawthorne unit in Missouri) or 18 months (Holcomb 2 in Kansas, Whelan Energy Center in Nebraska) at a higher NO_x limit (0.12 lb/MMBtu) to evaluate and optimize the SCR control system.

1.30 CO BACT Analysis

The objective of this analysis is to determine BACT for CO emissions from the proposed Unit 2 Boiler. The rate of CO emissions from combustion sources is dependant upon the combustion efficiency of the source. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion

can minimize CO emissions. Control of CO emissions can be achieved by application of combustion controls or by treatment of the flue gas after combustion. Often, measures used to minimize or control emissions of NO_x can result in incomplete combustion and increased CO emissions. Therefore, an acceptable compromise is necessary to achieve the lowest NO_x emission rate possible while still keeping CO emissions as low as possible.

CO Formation. CO formation occurs primarily through incomplete combustion. The oxidation of CO to carbon dioxide (CO₂) is dependent on temperature, residence time during the combustion process, and the amount of excess O₂ present. Since temperature and residence time are critical factors in formation of CO, smaller boilers often emit more CO than larger combustion units, because these units have less high-temperature residence time needed to achieve complete combustion.

1.31 Identification of CO Control Technologies

As stated previously, CO emissions can be controlled at the combustion source or through post-combustion control of the flue gas exhaust. The following technologies have been identified for control of CO emissions: catalytic oxidation, thermal oxidation, SCONO_xTM, and combustion controls. Catalytic oxidation, thermal oxidation, and SCONO_x are all post-combustion controls designed for the exhaust gas stream.

Catalytic Oxidation

There are a variety of manufacturers who offer oxidation catalysts to control CO emissions. The catalysts are a flue gas treatment technology with a typically honeycomb type of arrangement to allow the maximum surface area exposure to a given gas flow. CO catalysts are generally precious metal based. Catalytic oxidation has never been applied to a coal-fired unit. The use of an oxidation catalyst with sulfur-containing fuels can promote oxidation of SO₂ to SO₃, which can readily form H₂SO₄ in the presence of moisture. Oxidation catalysts also require a minimum temperature (>500 °F) for proper operation, which would necessitate that the catalyst be installed upstream of the FGD system and fabric filter. The particulate loading of the flue gas stream upstream of the fabric filter would be higher than the design capacity of any oxidation catalyst. In addition, trace elements that are present in coal and resulting combustion gases, in particular chlorine, may foul an oxidation catalyst and dramatically reduce its effectiveness. There are currently no known pulverized coal boilers that are equipped with oxidation catalysts, and for the reasons listed above, use of a catalytic oxidation system for the proposed pulverized coal-fired boilers is not considered technically feasible.

Thermal Oxidation

High temperature oxidation is another method for controlling emissions of CO in the flue gas. This type of system would be added at the exit of a baghouse, and has been reported to achieve up to 95% reduction of CO in the exhaust gas on other types of industrial facilities with much higher CO emissions and lower flow rates than the proposed Unit 2 boiler. Because a coal boiler is essentially a thermal oxidation device, adding this type of control would seem to be redundant. The application of thermal oxidation would require additional fuel usage, and would result in secondary emissions from that combustion. A review of the EPA's RACT/BACT/LAER Clearinghouse for pulverized coal boilers did not reveal any documentation of any facilities that have specified thermal oxidation as BACT. Therefore, thermal oxidation is not considered further as an option for the proposed PC boiler at NCS.

SCONO_x™

SCONO_x technology utilizes the same principles as catalytic oxidation for CO control. The SCONO_x bed uses a coating of the same catalyst material as that in an oxidation catalyst, which is used primarily to oxidize NO to NO₂, but also oxidizes CO to CO₂. To date, there is very limited commercial application of SCONO_x and thus very little emissions data available for review. Due to the fact that SCONO_x technology is very similar to catalytic oxidation, all the technical limitations for that technology also apply to SCONO_x. The SCONO_x technology for CO control has not been installed on coal-fired boilers, and therefore this control is not considered technically feasible for the proposed application.

Combustion Controls

CO emissions primarily result from incomplete combustion. The oxidation of CO to CO₂ is dependent upon temperature and residence time of the combustion process. The use of good combustion practice (GCP) such as high combustion temperatures, adequate combustion air, and proper air/fuel mixing can minimize CO emissions. Proper design and operation of a pulverized coal-fired boiler effectively acts like a thermal oxidizer for control of CO emissions. Additionally, there are no incremental costs associated with GCP for CO controls. Therefore, GCP is considered a feasible control technology for CO emissions.

1.32 Proposed CO BACT Selection

Based on the CO control technologies presented above, GCP is the only remaining technology for this application and is the proposed CO BACT for the Unit 2 boiler. None of the other control technologies have been proposed or demonstrated for use on a pulverized coal-fired boiler. Table 3 lists the CO emission limitation proposed as BACT under typical operating ranges for the Unit 2 boiler.

1.33 BACT Selection Review for CO

Information was obtained concerning recently proposed or permitted coal-fired power projects within the past three years. In all cases, GCP has been determined as BACT for control of CO emissions from these sources. Additionally, the proposed CO permit limit (0.16 lb/MMBtu) is comparable with other recently issued permitted and newly operating facilities such as Holcomb Unit #2 (0.15), Council Bluffs Unit 4 (0.154), and Hawthorn (0.16).

1.40 PM/PM₁₀ BACT Analysis

The objective of this analysis is to determine BACT for PM and PM₁₀ emissions (and any necessary visible emission standards) from the proposed Unit 2 boiler. In addition, BACT for other PM/PM₁₀ emitting sources is discussed in section 1.43.

PM/PM₁₀ Formation. PM emissions from utility boilers are a function of the boiler burner configuration, operation practices, coal properties and pollution control equipment. Uncontrolled PM emissions include ash from the non-combustibles in coal as well as unburned carbon resulting from incomplete combustion. When combusting pulverized coal, such as proposed for Unit 2, PM emissions are primarily composed of inorganic ash residue because combustion is nearly complete, resulting in minimal unburned carbon from incomplete combustion. PM₁₀ emissions are classified as filterable and condensable. Filterable PM₁₀ is the portion of total PM₁₀ present in the exhaust stream as a solid or liquid, and which is typically measured on an EPA Method 5 filter (40 CFR 60, Appendix A). Condensable PM₁₀ is the portion of

PM₁₀ that is initially present as a gas in the exhaust stream, but condenses to a liquid or solid state at cooler ambient temperatures.

1.41 Identification of PM Control Technologies

Control of PM/PM₁₀ emissions is achieved through the addition of equipment downstream of the combustion device. Three control technologies have been identified as alternatives for Unit 2: fabric filter baghouses, electrostatic precipitators (ESPs), and wet electrostatic precipitators (WESP). These technologies are considered to have the highest control efficiency of all particulate control options.

Fabric Filter Baghouse

Fabric filtration in a baghouse consists of a number of filtering bags that are suspended in a housing. The particulate-laden gas passes through the housing and collects on the fabric of the filter bag. Accumulated particulate matters on the bag surfaces enhance the bag's filtering efficiency. Periodically, the accumulated material or "cake" is removed from the bags through the use of a physical mechanism such as shaking or blasting the bags with compressed air. The dust is collected in a hopper and eventually removed. Fabric filtration has been widely used in coal combustion sources since the early 1970's and is considered a technically feasible control option for Unit 2.

Electrostatic Precipitator

ESPs remove PM from the flue gas stream using the principle of electrostatic attraction. PM in the exhaust stream is charged with a very high direct current (DC) voltage, and the charge particles are attracted to oppositely charged collection plates in the ESP. PM collected by the ESP continues to accumulate on the plates until removed by rapping the electrodes. The dust is then collected into a hopper for disposal. As opposed to baghouses, ESPs can handle large gas streams, high particulate loading and can operate at higher temperature and pressure conditions with wet or dry gas streams. However, the ESP is less effective at capturing fine particles than the baghouse. Very fine particles cannot carry a strong enough electrical charge to result in complete collection in an ESP. When using a dry flue gas desulfurization (FGD) system for SO₂ control, a much higher loading of fine particles is produced, making it more difficult to achieve acceptable control of particulate matter with an ESP as compared to a baghouse.

Wet Electrostatic Precipitator

Wet electrostatic precipitators (WESP) operate using the same principles as a standard ESP, but the final cleaning step is different. The collection surfaces are cleaned with water that can be delivered from spray nozzles or by condensing moisture from the flue gas. WESPs are effective in reduction of particle re-entrainment since the surfaces of the collection plates are constantly cleaned with liquid. WESPs also operate under higher electrical power than standard ESPs and enable higher reduction of very small particles. Operation of a WESP requires the collection and treatment and/or disposal of wastewater containing fly ash from the boiler.

1.42 Top-Down Ranking

The PM control technologies that are considered technically feasible for implementation on Unit 2 have been ranked from most to least effective in terms of emission reduction potential. Table 7 summarizes the control technology and ranking.

Table 7 – PM Control Technology Summary & Top-Down Ranking

Identified Control Technology	Potential to control PM emissions	Available and demonstrated effective	In service on similar systems	Technically feasible for Unit 2	% PM Reduction
Fabric Filter	Yes	Yes	Yes	Yes	99.9%
ESP	Yes	Yes	Yes	Yes	>99% ^a
Wet ESP	Yes	Yes	Yes	Yes	>99% ^a

^a Control efficiency varies for large and small particles and type of coal combusted.

1.43 Proposed PM/PM₁₀ BACT Selection

The proposed PM/PM₁₀ BACT for Unit 2 is use of a fabric filter baghouse. Based on the above top-down ranking of control technologies, fabric filters provide an equal or higher level of PM control in comparison to other technologies. Therefore, fabric filters are considered the “top” level of control. Additionally, the use of a baghouse does not have any significant adverse energy, environmental, or economic impacts. Because OPPD proposes to use the highest available level of PM control for Unit 2, a cost analysis and further technology review has not been included in this BACT analysis. Table 3 lists the PM emission limitation proposed as BACT under typical operating ranges for the Unit 2 Boiler.

Additionally, since the fabric filter baghouse will be controlling particulate emissions (the primary cause of opacity) down to permitted BACT levels, a separate visible emission standard is not necessary. In other words, BACT for visible emissions is the use of a fabric filter baghouse.

BACT must also be considered for other new or modified PM/PM₁₀ emitters at NCS even though they represent less than 10% of the total PM₁₀ emissions combined. These include the cooling tower (Emission point 208), the coal/ash/lime storage and handling system (Emission points 202, 203, 204, 211), and the existing coal tripper system (Emission points 105 and 106). The required use of a high efficiency drift eliminator is considered BACT for the cooling tower. BACT for storage bins, coal/ash/lime handling, and existing coal tripper system is considered the use of fabric filter baghouses. Fugitive emissions from the haul roads and coal storage pile have not been modified and experience no change in the method of operation, therefore BACT application is not required for these emission points. To minimize particulate emissions from these fugitive emission sources, OPPD will utilize only paved haul roads and maintain the existing use of dust suppressants and telescoping drop points at the coal storage pile. BACT is not required for the existing coal handling equipment that is not being modified (Emission points 109, 110, 111) to handle the increased coal throughput.

1.44 BACT Selection Review for PM/PM₁₀

Fabric filter baghouses are the most common control of PM₁₀ from PC boilers and are listed as BACT for PM/PM₁₀ in the vast majority of the PC boiler applications. The proposed BACT limit is 0.018 lb/MMBtu. Emission rate averaging time shall be based on the performance testing protocol submitted by OPPD and is generally averaged over the period of 3 test runs of at least 60 minutes in duration each. OPPD originally proposed a BACT limit of 0.027 lb/MMBtu (total PM) presumably based on the recently issued Council Bluffs Energy Center Unit 4 (CBEC4) permit limit. However, CBEC4’s total PM limit is the highest limit found of recently issued permits. Total PM limits were found as low as 0.018 lb/MMBtu, including one operating PC boiler (Hawthorn) and the most recently issued PC boiler permit in Nebraska, Whelan Energy Center Unit 2.

Performance testing data from KCP&L's Hawthorn plant was obtained from the Kansas City Air Quality Program. Hawthorn has a PM limit of 0.018 lb/MMBtu which includes condensable particulates. The latest available testing results (2001, 2002, 2003, and 2004) show that the Hawthorn facility met their emission limit, with their 2004 results being 0.0166 lb/MMBtu according to the local permitting agency (KCAQ). Thus, the Department believes that a total PM limit of 0.018 lb/MMBtu is the appropriate limit and does provide an adequate compliance margin.

1.50 VOC BACT Analysis

The objective of this analysis is to determine BACT for VOC emissions from the proposed Unit 2 Boiler. As with CO emissions, VOC emissions from combustion sources are dependent upon the combustion efficiency of the source. Control of VOC emissions can be achieved by application of combustion controls or by treatment of the flue gas after combustion.

VOC Formation. Like CO emissions, VOC emissions are the result of incomplete combustion of coal in the boiler. Combustion residence time, temperature, or turbulence will affect the concentrations of organic compounds in the flue gas.

1.51 Identification of VOC Control Technologies

Two control technologies have been identified for control of VOC emissions: catalytic oxidation and combustion controls. Thermal oxidation is not considered a feasible technology for VOC control due to the low VOC concentration in the exhaust gas stream of a well operated combustion device.

Catalytic Oxidation

Catalytic oxidation has been used to control both CO and VOC emissions primarily from combustion turbines firing natural gas. The use of a catalytic oxidizer has never been applied to a coal fired unit and has not been demonstrated for this application. The use of an oxidation catalyst with fuels containing sulfur, such as coal, would result in conversion of SO₂ to SO₃, and would cause corrosion to the flue gas system. There are currently no oxidation catalysts developed for coal fired boilers.

Combustion Controls

The use of good combustion practice (GCP) such as high combustion temperatures, adequate combustion air, and proper air/fuel mixing can minimize both VOC and CO emissions. When a pulverized coal-fired boiler is operated properly, it effectively acts like a thermal oxidizer for destruction of organic compounds. The use of GCP requires no additional or incremental cost for control of both VOC and CO emissions. Therefore, GCP is considered a feasible control technology for VOC emissions.

1.52 Proposed VOC BACT Selection

The use of GCP has been selected as the only feasible control option for VOC emissions from the pulverized coal-fired boiler, and thus is proposed as BACT. Table 3 lists the VOC emission limitation proposed as BACT under typical operating ranges for the Unit 2 boiler.

1.53 BACT Selection Review for VOC

Information was obtained concerning recently proposed or permitted coal-fired power projects within the past three years. In all cases, GCP has been determined as BACT for control of VOC emissions from these sources. Additionally, the proposed VOC permit limit (0.0034 lb/MMBtu) compares very

favorably to with other recently issued permitted and newly operating facilities such as Holcomb Unit #2 (0.0035), Council Bluffs Unit 4 (0.0036), and Hawthorn (0.0036).

1.60 Fluorides BACT Analysis

Fluoride Formation. Similar to SO₂, fluoride emissions are formed from coal combustion due to trace concentrations of fluoride-containing compounds in the fuel. Fluoride emissions are primarily in the form of hydrogen fluoride (HF, or hydrofluoric acid). HF is water soluble and is readily controlled by acid gas scrubbing systems.

1.61 Identification of Fluoride Control Technologies

Three control technologies have been identified for control of fluoride emissions from pulverized coal-fired boilers. They are SDA's in combination with an ESP, SDA's in combination with a baghouse, and caustic wet scrubbers. As stated previously, HF is very readily removed in the SDA reaction with the flue gas stream. In addition, fabric filters are considered to have higher residual acid gas removal efficiencies than ESPs. Thus, the SDA in combination with the baghouse is considered the top control option for control of fluorides from the Unit 2 boiler.

1.62 Proposed Fluoride BACT Selection

SDA in combination with a baghouse has been selected as the control option for SO₂ and is also considered the top control option for control of fluorides. The SDA system is expected to achieve HF control of at least 92.5%, yielding a maximum fluoride emission rate 0.0004 lb/MMBtu, based on the coal analysis information provided by OPPD (fluorine content of 59 ppm “dry” basis, and typical moisture content of 28%) and the calculation provided below. Averaging time will be based on the test method and protocol submitted by OPPD and approved by the Department.

$$\frac{59 \text{ lb} \cdot \text{F}}{10^6 \text{ lb} \cdot \text{coal}, \text{dry}} \times \frac{20 \text{ lb} \cdot \text{HF}}{19 \text{ lb} \cdot \text{F}} \times \frac{(1 - 28\%) \text{ lb} \cdot \text{coal}, \text{dry}}{\text{lb} \cdot \text{coal}, \text{wet}} \times \frac{\text{lb} \cdot \text{coal}, \text{wet}}{8,350 \text{ BTU}} \times (1 - 92.5\%) = 0.0004 \text{ lb} \cdot \text{HF} / \text{MMBtu}$$

1.63 BACT Selection Review for Fluorides

A review of the RBLC database did not provide any information regarding controls and limits for fluorides for pulverized coal-fired boilers. The updated national coal power projects list from the EPA CATC website and the additional information obtained from the individual permitting authorities have shown that an SDA in combination with a fabric filter baghouse is the control option for most proposed and/or permitted pulverized coal units.

2.0 Air Quality Impact Analysis:

This air quality impact analysis for the proposed Unit 2 modification consists of two components. The first component of the air quality analysis consists of a preliminary modeling analysis of all new or modified emission sources at the facility (Unit 2 boiler stack, cooling tower, lime/ash/carbon storage silo bin vents, new ash landfill and coal pile coal areas, coal conveying system, and fugitive truck emissions), to determine if the emissions from the new sources would cause ambient pollutant concentrations in excess of 1) concentration thresholds above which preconstruction ambient air quality monitoring may be required, or 2) significant impact levels (SILs), which determine if further modeling is required on a pollutant-by-pollutant basis. The first component analysis was completed for CO, NO₂, PM₁₀, and SO₂.

The second component of the analysis consists of a refined modeling analysis to demonstrate that the proposed facility will not cause or contribute to any violations of applicable Ambient Air Quality Standards (AAQS) or PSD Increments for those pollutants with concentrations above the respective SILs. This analysis includes sources which contribute to baseline concentrations of each pollutant and sources which have been determined to consume available increment for each pollutant. The second component analysis, including of all appropriate regional emission sources (other nearby facilities), was completed only for 24-hour average PM₁₀, and for 3-hour and 24-hour SO₂, because these were the only pollutants and averaging periods for which maximum concentrations from the NCS Unit 2 project sources were predicted to exceed SILs (first component analysis).

Source Input Data

The stack parameters and emission rates for the emission points modeled can be found in the PSD application and in supplemental information received by the Department on October 20, 2004. PSD increment-consuming sources, major or minor, within 50 km of the proposed facility were included in the PM₁₀ and SO₂ refined analyses.

2.10 Preliminary Analysis for Significant Impacts

The purpose of the preliminary dispersion modeling analysis was to determine if emissions from operation of Unit 2 and associated new emission sources would cause ambient pollutant concentrations in excess of concentration thresholds above which pre-application ambient air quality monitoring may be required. In addition, the results were reviewed to determine if a SIL would be exceeded for any pollutant. The latest version of the EPA Industrial Source Complex Short-Term dispersion model (ISCST3, Version 02035) was used for this analysis.

The meteorological data used for this analysis consisted of five years (1998-2002) of National Weather Service surface data from Eppley Airport in Omaha (station number 14942) and mixing height data for Omaha (station number 94980).

Table 8 shows the results of the SIL and pre-application ambient monitoring threshold analysis. The results indicate that the operation of the NCS Unit 2 project will not cause a significant impact in the area surrounding NCS for the 1-hour or 8-hour averaging periods for CO, nor for the annual averaging period for SO₂, NO₂, or PM₁₀. Short-term PM₁₀ and short-term SO₂ concentrations (3-hr and 24-hr) exceed the SIL, therefore these two pollutants were further evaluated in this refined modeling analysis.

Table 8 - Maximum Modeled NCS Unit 2 Project Concentrations, Significant Impact Levels, and Pre-application Monitoring Thresholds

Pollutant	Averaging Period	Modeled	SIL	Pre-application Monitoring
		Concentration ($\mu\text{g}/\text{m}^3$)	($\mu\text{g}/\text{m}^3$)	Threshold Concentration ($\mu\text{g}/\text{m}^3$)
CO	1-hr	487	2,000	NA
	8-hr	70	500	575
SO ₂	Annual	0.47	1.0	NA
	24-hr	22	5.0	13
	3-hr	290	25.0	NA
PM ₁₀	Annual	<1.0	1.0	NA
	24-hr	9.9	5.0	10
NO ₂	Annual	0.87	1.0	14

The 24-hr SO₂ impact also exceeds the *Pre-application Ambient Monitoring Thresholds*. This means that the source could be required to conduct ambient air monitoring prior to submitting their PSD application in accordance with 40 CFR 52.21(m). However, the Department is not requiring OPPD to conduct pre-application monitoring based on the availability of representative monitoring data for SO₂ located in Omaha, approximately 50 miles to the north of NCS. The most recent three years of data (2000-2002) indicates background concentrations of SO₂ far below the respective ambient air quality standards. Omaha monitoring data is considered by the Department as a conservative upper bound to the more rural area south of Nebraska City due to the greater number of power plants, industries, vehicles, and small urban sources.

2.20 Refined Modeling Analysis for NAAQS and PSD Increment Compliance

The purpose of the final refined modeling analysis was to demonstrate that the proposed facility will not cause or contribute to violations of applicable NAAQS or PSD Increments for PM₁₀ and SO₂ (3 & 24-hour only). Note: refined modeling results are not presented for annual SO₂ or PM₁₀ emissions, based on the results of the preliminary modeling analysis which showed that annual impacts are insignificant. The AAQS and PSD increments are shown in Table 9. The Nebraska and National AAQS and PSD increments are identical.

Table 9 - Nebraska and National Ambient Air Quality Standards and PSD Increments For PM₁₀ and SO₂^a

Pollutant	Averaging Period	Ambient Air Quality Standards		PSD Class II Increments	
		National	Nebraska	National	Nebraska
PM ₁₀	24-hour ^b	150	150	30	30
	Annual	50	50	17	17
SO ₂	3-hour ^b	1,300	1,300	512	512
	24-hour ^b	365	365	91	91

^a All standards and increments are in units of $\mu\text{g}/\text{m}^3$.

^b Concentration or increment is allowed to be exceeded once per year at a single receptor. A second exceedence of the standard or increment constitutes a violation of the standard.

This ambient air quality impact analysis takes into account the combined impacts of emissions from the existing and proposed NCS sources, contributions from nearby major and minor sources, and background

concentrations due to distant major and minor sources and natural sources. Based on the potential emissions from NCS and other sources' allowable and actual emissions, this analysis demonstrates facility compliance with AAQS and PSD Increments for PM₁₀ and SO₂.

2.21 PM₁₀ Results

The PM₁₀ results for PSD Class II Increment consumption and NAAQS compliance demonstration are described below.

PSD Increment

The ISCST3 model output files for the PM₁₀ increment consumption analysis indicate that the total PM₁₀ concentrations for the 24-hour averaging period will not cause an exceedence of the allowable PSD increment of 30 ug/m³. Results of the PM₁₀ PSD increment consumption analysis are summarized in Table 10.

Table 10 - Maximum Predicted PM₁₀ Increment Consumption

Averaging Period	Year	UTM Coordinates (m)		H2H Increment Consumption ^a	Allowable PSD Increment (ug/m ³)
		X	Y	(ug/m ³)	
24-hour	1998	265,675	4,499,701	21	30
	1999	265,699	4,499,844	20	
	2000	265,714	4,499,970	18	
	2001	265,699	4,499,844	22	
	2002	265,707	4,499,892	24	

^a Value shown is highest-second-high (H2H) concentration, since one exceedence of the short-term standard is allowed per year.

Ambient Air Quality

The ISCST3 model output files for the PM₁₀ analysis also indicate that the total PM₁₀ concentrations due to all modeled sources, plus background concentrations, are below the NAAQS. Results of the PM₁₀ NAAQS analysis are summarized in Table 11.

Table 11 – Maximum Predicted Ambient PM₁₀ Concentrations

Averaging Period	Year	UTM Coordinates (m)		Background (ug/m ³)	Modeled (ug/m ³)	Total (ug/m ³)	AAQS (ug/m ³)
		X	Y				
24-hour	1998	265,713	4,499,952	60	27	87	150
	1999						
	2000						
	2001						
	2002						

NOTE: The value shown is the highest-sixth-high (H6H) result over the entire five years.

2.22 SO₂ Results

The SO₂ results for PSD Class II Increment consumption and NAAQS compliance demonstration are described below. For the SO₂ analysis, a "maintenance" scenario was evaluated for the 3-hour and 24-hour averaging periods. The 3-hour SO₂ analysis used an emission rate equivalent to 60% control on an uncontrolled emission rate of 1.2 lb/MMBtu to account for brief periods (up to 4 hours) when one of the two SDA atomizer modules needs to be replaced. The normal schedule for change out (with a spare) and replacement of the atomizer is once every 3-4 months. When one of the atomizers is out of service, the SO₂ emissions from Unit 2 would be controlled only to 60% by the second SDA module.

A separate scenario was modeled for the 24-hour SO₂ analysis, by assuming one 4-hour period of SDA maintenance, as described in the paragraph above, occurs within a 24-hour period. The 24-hour and 3-hour SIL analysis was conducted using these "maintenance" scenario emission rates for the entire five-year period of meteorology, so that the 3-hour and 24-hour results are very worst-case estimates of maximum potential impacts. This analysis used the SO₂ emission rates equivalent to the proposed permit limits.

PSD Increment

The results of the SO₂ increment consumption analysis indicate that the operation of NCS Unit 2 will not cause an exceedence of the 3-hour or 24-hour allowable PSD increments. Results of the SO₂ PSD increment consumption analysis are summarized in Table 12.

Table 12 - Maximum Predicted SO₂ Increment Consumption

Averaging Period	Year	UTM Coordinates (m)		H2H Increment Consumption ^a (ug/m ³)	Allowable PSD Increment (ug/m ³)
		X	Y		
3-hour	1998	263,100	4,500,000	182	512
	1999	263,100	4,500,000	204	
	2000	262,900	4,499,600	202	
	2001	263,100	4,499,000	173	
	2002	262,600	4,499,500	182	
24-hour	1998	266,900	4,499,400	20	91
	1999	264,500	4,504,500	22	
	2000	267,500	4,493,500	27	
	2001	261,600	4,500,800	24	
	2002	261,800	4,500,200	20	

NOTE: Values shown are the highest-second-high (H2H) concentrations, since one exceedence of the short-term standard is allowed per year.

Ambient Air Quality

The SO₂ results for AAQS compliance are shown in Table 13 for 24-hour and 3-hour concentrations, including contributions from existing sources of SO₂ emissions in the project area. As shown in the Table, the 24-hour and 3-hour concentrations are predicted to be below the ambient standards.

Table 13 – Maximum Predicted Ambient SO₂ Concentrations

Averaging Period	Year	UTM Coordinates (m)		Background (µg/m ³)	Modeled (µg/m ³)	Total (µg/m ³)	AAQS (µg/m ³)
		X	Y				
3-hour	1998	263,100	4,500,000	120	182	302	1,300
	1999	263,100	4,500,000		204	324	
	2000	262,900	4,499,600		202	322	
	2001	271,500	4,518,500		173	293	
	2002	262,600	4,499,500		182	302	
24-hour	1998	271,500	4,518,500	48	43	91	365
	1999	248,500	4,511,500		36	84	
	2000	246,500	4,510,500		38	86	
	2001	273,500	4,518,500		37	85	
	2002	271,500	4,518,500		36	84	

NOTE: The values shown for the 3-hour and 24-hour averaging periods are the highest-second-high (H2H) results, since one exceedence of the short term standard is allowed per year at each location.

2.30 Air Quality Impact Summary

The analyses described above demonstrate that the addition of NCS Unit 2 will not significantly contribute to any exceedence of the 24-hour allowable PM₁₀ PSD increments or AAQS for any episode. The analysis also demonstrates that the addition of NCS Unit 2 will comply with all applicable SO₂ AAQS and PSD increments and will not have a significant impact on annual SO₂, NO₂ or PM₁₀ concentrations, or CO 1-hour or 8-hour concentrations.

3.00 Additional Impacts Analysis

An Additional Impacts Analysis, as required by 40 CFR 52.21(o), describes air quality and related impacts due to associated growth and construction, as well as potential impacts of atmospheric emissions on soils, vegetation, and visibility impairment. This analysis indicates no adverse impacts. This information is summarized as follows:

Visibility Impacts

A plume visibility screen modeling analysis was performed for this project. Because the nearest Federal Class I areas are several hundred kilometers away from the proposed facility site, the potential impacts at Arbor State Historical Park in Nebraska and Waubonsie State Park in Iowa were evaluated. Arbor State Historical Park is approximately 11.3 km north and slightly west of NCS, and Waubonsie is approximately 7.3 km northeast of the facility.

The PM and NO_x emission rates input to the VISCREEN model was a conservative maximum based on 100% of the design heat input rate from NCS Unit 2 and the proposed emission limits from the permit. The results of the Level 1 screening analysis indicated that emissions from the Unit 2 boiler could result in exceedances of the visibility screening criteria inside the identified Class II areas. Therefore, a Level 2 analysis was performed and showed that visible plume impacts may be noticed approximately 47 hours per year at Waubonsie and 339 hours per year at Arbor State Parks. However, because the VISCREEN results are known to be very conservative, it is concluded that plumes of air pollutants from NCS Unit 2 will be

insignificant and occur even more rarely than indicated by the level 2 analysis. The PSD Application submitted by the source includes more details to support this conclusion.

Because NCS Unit 2 will emit a plume containing moisture, both from combustion products and from water added in the FGD system, it is expected that the new stack will occasionally have a visible moisture plume, especially on cold days. Given the very flat terrain in the area, the moisture plume may, in fact, be visible in the distance to an observer at the Arbor State Historical and Waubonsie State Parks. However, such moisture plumes would occupy only a tiny fraction of the observer's horizon, and thus are not considered an adverse visible impact.

The evaporated water exiting the cooling towers forms fine water droplets also creating a visible plume. The generation of fog or icy conditions could occur if the plume arrives at a road at surface level. As detailed in the PSD application, no impacts are expected to occur on I-29 from fog or icing due to the distance separating I-29 from the NCS Unit 2 cooling tower (3.5 km).

The proposed Unit 2 would use ammonia in the SCR system for the control of NO_x emissions. While the SCR system is designed so that most of the injected ammonia would react with NO_x, there will always be some amount of unreacted ammonia, perhaps up to 10 ppm in the exhaust gases, from the operation of the SCR system. Because ammonia can contribute to fine particle formation, it can be an issue with respect to regional haze or regional visibility reduction. The Great Plains states generally use a lot of ammonia for farm fertilizer, and produce ammonia from farming operations such as feedlots, etc. Given the relatively high "natural" ammonia emissions in this area, it is not expected that ammonia slip from the proposed facility would contribute significantly to the production of fine particles in the atmosphere.

As documented in the PSD Application, impacts of the proposed project on soils, vegetation, and visibility from atmospheric emissions are expected to be negligible.

4.00 Air Quality Monitoring

Pre-application monitoring is required under the PSD regulations in 40 CFR 52.21(m)(1) for those modifications at a source that are anticipated to produce ambient concentrations equal to or greater than thresholds indicated in 40 CFR 52.21(i)(8)(i). NCS's preliminary dispersion modeling analysis demonstrates that the potential ambient impacts exceed the monitoring thresholds for SO₂.

The Department received a request from OPPD to use existing representative monitoring data instead of conducting pre-application monitoring. The Department issued a letter on April 21, 2004, waiving pre-application monitoring for SO₂ and that representative monitoring data from Omaha was sufficient to address the requirements of 40 CFR 52.21(m)(1).

B. New Source Performance Standards (NSPS):

Federal NSPS found in 40 CFR 60 have been adopted by reference within Title 129, Chapter 18. In addition to Subpart A, General Provision, the Unit 2 boiler is subject to opacity and emission limitations for NO_x, SO₂ and PM found in Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. The auxiliary boiler is subject to the limitations for SO₂ and Opacity found in Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. The new coal storage bunkers and the existing coal conveying leg that is being extended are subject to the opacity limitation found in Subpart Y, Standards of Performance for Coal Preparation Plants. Both of these emission points are controlled by the tripper dust collectors, EP 105 & 106.

Unit 2 Boiler

As stated in Subpart Da, 40 CFR 60.44a(d)(1), no new source owner or operator shall cause to be discharged into the atmosphere from any affected facility for which construction commenced after July 9, 1997 any gases which contain nitrogen oxides (expressed as NO₂) in excess of 200 nanograms per joule (ng/J) (1.6 lbs/MW-hr) gross energy output, based on a 30-day rolling average. The maximum rated gross energy output of Unit 2 is proposed to be 720 MW, based on the average annual wet bulb temperature. At this energy output the applicable NSPS NO_x emission limitation based on annual average ambient temperature conditions will be:

$$(1.6 \text{ lbs/MW-hr}) \times (720 \text{ MW}) = 1,152 \text{ lb/hr (0.18 lb/MMBtu)}.$$

Additionally, per 40 CFR 60.42a(a)(1) and (2), no owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which contain PM in excess of 13 ng/J (0.03 lb/MMBtu) and 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel. The proposed baghouse will easily remove over 99% of the PM generated by the combustion process, and the proposed PM limit of 0.018 lb/MMBtu is less than the NSPS limit of 0.03 lb/MMBtu. The opacity is limited to 20% and the source must install a Continuous Opacity Monitoring System (COMS) or use other approved monitoring methods per 40 CFR 60.47a(a). Upstream monitoring of PM emissions is not required (in order to calculate control efficiency) per 40 CFR 60.46a(a).

Finally, as stated in 40 CFR 60.43a(a)(2), no owner or operator shall cause to be discharged into the atmosphere from any affected facility, which combusts solid fuel, gases which contain SO₂ in excess of 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input. These limits apply on a 30-day rolling average. The proposed spray dryer absorber (SDA) system will remove at least 90% of the SO₂ from the design maximum sulfur coal (maximum sulfur of 1.2 lb/MMBtu), and will have outlet emissions of no more than 0.095 lb/MMBtu on a 30-day rolling average basis. Monitoring is required at both the inlet and outlet of the SO₂ control system per 40 CFR 60.47a(b)(1) or as allowed under 40 CFR 60.47a(b)(3).

The following table summarizes the NSPS Subpart Da limitations applicable to the proposed Unit 2, in comparison to the BACT permit limits.

Table 14 - NSPS Subpart Da Emission Limitations Applicable to Unit 2 ^a

Pollutant	% Reduction Requirement	NSPS Limit lb/MMBtu	Limit lb/hr	BACT Permitted lb/MMBtu
NO _x	Not applicable	0.18	1,166	0.07
PM	99%	0.03	194.3	0.018
SO ₂	70%	0.36	2,332	0.095

^a The above listed NSPS emission limitations are provided for reference only and will be superceded by more stringent BACT limitations for each of the listed pollutants. (See Section A of this Fact Sheet)

A Continuous Emissions Monitoring System (CEMS) must be installed to measure NO₂, SO₂, and CO₂ (or O₂) per 40 CFR 60.47a. The Acid Rain rules also require the installation and operation of a CEMS.

Auxiliary Boiler 2

In addition to the standard NSPS initial notification and general reporting requirements found in Subpart A, the auxiliary Boiler has the following requirements from Subpart Db pertaining to PM and SO₂ emissions:

Particulate Matter: The NSPS limits opacity to no more than 20 percent, except for one 6-minute period per hour of not more than 27 percent opacity pursuant to 40 CFR 60.43b(f). A Continuous Opacity Monitoring System (COMS) is also required in accordance with 40 CFR 60.48b(a), or an alternate monitoring plan can be requested in accordance with 40 CFR 60.13(i)(2) since the boiler is “infrequently operated” (i.e. limited operation to 500 hours or less annually).

Fuel Sulfur: The fuel combusted in the auxiliary boiler shall not contain greater than 0.5 percent sulfur by weight pursuant to 40 CFR 60.42b(j). OPPD proposes to limit their fuel oil to 0.05% sulfur. Fuel supplier certifications will be used to demonstrate compliance with this requirement per 40 CFR 60.49b(r).

Nitrogen Oxides: The NSPS emission limits for NO_x are not applicable since OPPD has accepted an annual capacity factor limit of less than 10% pursuant to 40 CFR 60.44b(k). OPPD proposes to limit their usage to 500 hours per year.

Coal Handling

The new coal storage bunkers and extended coal conveyer leg are subject to Subpart Y since they are considered affected facilities that commenced construction or modification after October 24, 1974. In addition to the BACT emission limit, the only other applicable requirement is that exhaust gases are limited to less than 20% opacity. The use of the existing coal tripper fabric filter dust collectors 105 and 106 on the coal system will ensure compliance with this requirement.

C. National Emissions Standards for Hazardous Air Pollutants (NESHAPs):

NESHAPs are the regulations that contain the Maximum Achievable Control Technology (MACT) standards, and their associated compliance and reporting requirements. They are listed under 40 CFR 63.

The applicability of the NESHAPs is identified in 40 CFR Part 63.40. These requirements apply to any owner or operator who constructs a major source of HAPs (greater than 10/25 tpy) after June 29, 1998 {the effective date of Section 112(g) of the Clean Air Act}. Unit 2 will be a new utility boiler proposed at an existing facility. Thus, from 40 CFR Part 63.41, the definition of *construct a major source* means “to fabricate, erect, or install at any developed site a new process or production unit which in an of itself has the potential to emit 10 tons per year of any HAP or 25 tons per year of any combination of HAP...”. The potential, controlled emissions of HAPs for the proposed NCS Unit 2 are greater than the major source thresholds. Therefore, the Unit 2 utility boiler will be subject to the NESHAP/MACT standards.

On December 14, 2000, the EPA announced that coal and oil-fired electric utility steam generating units would be added to the list of source categories under which a MACT standard will be developed. The Utility Boiler MACT (Subpart UUUUU) proposal was signed by EPA on December 15, 2003 and was published in the Federal Register on January 30, 2004. Since the proposed MACT standard has not yet been promulgated, a case-by-case MACT determination is required in accordance with Section 112(g) of the Clean Air Act.

The Department requested that OPPD submit a MACT analysis and determination request in a letter dated August 31, 2004. The Department received the MACT analysis on September 20, 2004. The following paragraphs summarize the Department's basis for its MACT determination, after consideration of the MACT analysis submitted by OPPD, and establishes the proposed emission limitations in accordance with Title 129, Chapter 27. In the discussion below, some reference is made to the MACT analysis and determination completed by the Iowa Department of Natural Resources (IDNR) for the Council Bluffs Energy Center – Unit 4 (CBEC4) permit. CBEC4 is a similar type and size of utility boiler located less than 50 miles away from the proposed Unit 2 boiler project.

Organic HAPs: Organic HAPs (HAPs that contain carbon, including dioxins/furans) and CO are emitted as a result of incomplete combustion. Because CO is a good indicator of complete combustion, there is often a strong correlation between the quantity of CO emissions and the formation of organic HAP emissions. As a result, CO will be used as a surrogate for organic HAP emissions. This is consistent with EPA's MACT standard for industrial, institutional, and commercial boilers (Subpart DDDDD). As a result of the BACT analysis presented in Section 1.30, CO emissions are limited to 0.16 lb/MMBtu. A positive MACT floor finding was concluded during the analysis of CBEC4 indicating a CO limit of 200 ppm corrected to 3% oxygen (approximately equivalent to 0.17 lb/MMBtu) was MACT for organic HAPs. Since the CO BACT limit is already lower than the MACT floor, the MACT limit for organic HAP will be set at a CO limit of 0.16 lb/MMBtu. A continuous emissions monitoring system will be required to monitor CO emissions to demonstrate compliance with the case-by-case MACT determination for CO emissions.

Acid gases: The acid gases hydrogen chloride (HCl, hydrochloric acid) and hydrogen fluoride (HF, hydrofluoric acid) are emitted from coal combustion as a result of trace amounts of chlorine (Cl) and fluorine (F) found in coal. As explained in section 1.11, a dry FGD system consisting of a spray dryer absorber (SDA) and baghouse is an effective method of neutralizing both HCl and HF since these acid gases are readily converted into solid salts when reacted with calcium based scrubbing agents. The Department considers the use of an SDA/baghouse system to be the MACT floor. Also as explained in the BACT analysis for fluorides (Section 1.60), the SDA/baghouse system is considered the top control technology and is expected to achieve HCl and HF emission reductions of over 95% and 92.5%, respectively, assuming typical chlorine and fluorine contents in the PRB coal to be burned in Unit 2.

Using the maximum expected concentration of chlorine and fluorine in the coal used at the facility (156 ppm and 59 ppm on a "dry" basis, respectively), and a control efficiency of 95% for HCl and 92.5% for HF, the MACT limit for HCl is 0.0008 lb/MMBtu (3-hr average) and the MACT limit for HF is equal to the BACT limit of 0.0004 lb/MMBtu (3-hr average, see Section 1.62). For comparison, the proposed emission limits for HCl (0.0008) and HF (0.0004) are less than 1/2 of the permitted rates of CBEC4. The calculation below indicates that the source should not have difficulty meeting the proposed limit based on the assumed 95% control and the coal analysis. The limit also provides a small compliance margin to account for variability in coal moisture and other factors.

$$\frac{156 \text{ lb} \cdot \text{Cl}}{10^6 \text{ lb} \cdot \text{coal}, \text{dry}} \times \frac{36 \text{ lb} \cdot \text{HCl}}{35 \text{ lb} \cdot \text{Cl}} \times \frac{(1 - 28\%) \text{ lb} \cdot \text{coal}, \text{dry}}{\text{lb} \cdot \text{coal}, \text{wet}} \times \frac{\text{lb} \cdot \text{coal}, \text{wet}}{8,350 \text{ BTU}} \times (1 - 95\%) = 0.0007 \text{ lb} \cdot \text{HCl} / \text{MMBtu}$$

Since there is a strong relationship between the reduction in SO₂ emissions and the reduction of acid gas emissions when using an SDA/baghouse system, the SO₂ CEMS will provide a demonstration of ongoing compliance with the MACT emission limits after initial performance testing.

Non-mercury metals: Non-mercury metals are emitted from coal-fired boilers primarily in the form of particulates. Control of these metals is predominately achieved by utilizing a PM control device such as a baghouse. Using PM control as a surrogate, the Department has concluded that the use of a baghouse to limit PM emissions as indicated in Table 3 is MACT for non-mercury metals.

Mercury(Hg): The mercury emissions rate was determined based upon the case-by-case analysis presented in the MACT analysis, review of the mercury emission information prepared by EPA, and the recent case-by-case MACT determination issued for CBEC4 in Iowa. A “beyond the floor” evaluation in the submitted MACT analysis, based on short-term test data from a PRB coal-fired facility (Sunflower Station Unit 1) indicates that a 90% reduction in Hg emissions may be approached with the use of a sorbent injection control system (particularly using halogenated activated carbon injection).

The Department agrees with this analysis, therefore, the use of a sorbent injection control system is considered MACT for Hg control on the Unit 2 boiler. The specific sorbent to be used for control of Hg emissions from NCS Unit 2 will be determined by OPPD after permit issuance, as there is still substantial research ongoing in the US to determine the best sorbents for various boiler types, emission control configurations, and coal types. Information submitted by OPPD indicates that the maximum expected Hg content of the incoming coal is 0.23 parts per million (ppm) on a “dry” basis, producing a potential Hg emission rate of 19.8 lb/Trillion Btu (Tbtu) (not controlled by any type of pollutant control system). The controlled emission rate is therefore expected to be no greater than 1.98 lb/Tbtu (assuming 90% control). This equates to an “output” based emission limit of approximately 18×10^{-6} lb/MWh (megawatt hours). The averaging period is a 12-month rolling average. Compliance will be determined using an EPA-approved continuous emission monitoring system (e.g. Performance Specification 12A in 40 CFR 60) or an EPA-approved continuous measurement sampling method (e.g. Method 324 in 30 CFR 63), both of which have been proposed as part of the Utility MACT.

For comparison, the proposed EPA standard (Subpart UUUUU), if promulgated, would limit mercury emissions from Unit 2 to 20×10^{-6} lb/MWh, or approximately 2.26 lb per trillion Btu (lb/TBtu) ($20 \times 10^{-6} \times 734 \text{ MW} / 0.006478 \text{ TBtu/hr}$). The existing NC1 boiler will be subject to the EPA regulations when promulgated, but may have different emission limits and timelines for compliance than Unit 2.

MACT for Auxiliary Boiler:

The MACT standard for industrial, institutional, and commercial boilers (Subpart DDDDD) was promulgated on September 13, 2004, (69 FR 55217) and is applicable to auxiliary boiler 2 since it is located at a major source of HAPs. The auxiliary boiler is categorized as a “limited use liquid fuel” since operation is limited to 500 hr/yr. The boiler is subject to the emission limits and work practice standards in this subpart, but does not have to demonstrate initial or continued compliance by testing. Instead, OPPD must demonstrate compliance in accordance with 40 CFR 63.7506(a)(1) & (a)(2) by certifying that they do not burn residual oil.

The emission limits specified in Subpart DDDDD are:

PM = 0.03 lb/MMbtu

HCl = 0.0009 lb/MMbtu

CO = 400 ppmvd @ 3% O₂

Emergency Generator:

The MACT standard for Stationary Reciprocating Internal Combustion Engines (RICE, Subpart ZZZZ) was promulgated on June 15, 2004. Since the generator engine is classified as an “emergency stationary RICE” it is only subject to the initial notification requirement per 40 CFR 63.6590(b).

Cooling Tower:

Since no chromium-based water treatment chemicals shall be used in the circulating water system of the cooling towers, 40 CFR 63, Subpart Q will not apply.

D. Acid Rain Program:

The proposed Unit 2 will be considered an affected unit for purposes of the acid rain rule because it is a utility unit that will generate more than 25 MW of electricity. The acid rain rule requires a facility to monitor opacity, and all sulfur dioxide, nitrogen oxides, and carbon dioxide emissions for each affected unit. Therefore, NCS will implement the applicable monitoring requirements of 40 CFR 75, Continuous Emission Monitoring. The proposed Unit 2 will also be subject to a requirement to submit an Acid Rain permit application per 40 CFR 72, to meet the SO₂ allowance requirements of 40 CFR 73, and to meet the NO_x emission limitations of 40 CFR 76. Note that the 40 CFR 76 NO_x limits are far less stringent than the applicable NSPS NO_x limit and the proposed BACT NO_x limit.

E. Chemical Accident Prevention (40 CFR 68):

The proposed NCS Unit 2 project is expected to require anhydrous ammonia storage (for the SCR system) of approximately 80,000 pounds. This will require the facility to prepare and file a Risk Management Plan (RMP) under Chemical Accident Prevention rules (40 CFR 68), prior to bringing a threshold quantity of ammonia (10,000 pounds) on site.

The proposed water disinfection is expected to be done using sodium hypochlorite which would not require an RMP. However, if chlorine is used and a storage volume of over 2,500 pounds is required, the RMP will also include chlorine.

F. Additional Title 129 Regulations:

Chapter 20 – Particulate Matter Emissions: The source is expected to comply with the emission limits for material handling in Section 001 since all coal/lime/ash emission points are required to operate with a baghouse. Limits for fuel combustion in Section 002 will be met with the required use of a baghouse on Unit 2 boiler and the use of distillate fuel oil for the auxiliary boiler and emergency generator as indicated in Table 15 below.

Table 15 – Chapter 20, Section 002 Fuel Combustion Calculations

Equipment	Maximum Heat Input Rate (MMBtu/hr)	Allowed PM Emissions (lb/MMBtu)	Potential PM Emissions (lb/MMBtu)
Unit 2 Boiler	6,478	0.13	0.018
Auxiliary Boiler 2	114	0.34	0.024
Emergency Generator	6.9	0.60	0.07

Chapter 24 – Sulfur Compound Emissions: The source will comply with the emission limit for equipment that burns fossil fuels since it combusts only low-sulfur PRB coal and utilizes a SDA system for SO_x removal. The required use of distillate fuel oil with a maximum sulfur content of 0.05% in the auxiliary boiler and emergency generator will ensure compliance for these emission units as show in Table 16 below.

Table 16 – Chapter 24, Fuel Combustion Calculations

Equipment	Maximum Heat Input Rate (MMBtu/hr)	Allowed SO_x Emissions (lb/MMBtu)	Potential SO_x Emissions (lb/MMBtu)
Unit 2 Boiler	6,478	2.5	0.095
Auxiliary Boiler 2	114	2.5	0.056
Emergency Generator	6.9	2.5	0.05

Chapter 27 – Hazardous Air Pollutants: Since the net increase in potential to emit of any single HAP and total HAP is greater than the 10/25 tpy thresholds listed in Section 003, MACT must be applied to potential HAP emitting units including the Unit 2 boiler, auxiliary boiler 2, and generator. Since the auxiliary boiler 2 and emergency generator are limited to 500 hours per year and burn exclusively low-sulfur distillate fuel oil, HAP emissions from these two units is minimal and no additional requirements are needed to meet MACT under Chapter 27. A case-by-case MACT analysis was submitted by OPPD to address the requirements of Chapter 27, Section 003 and 40 CFR 63, and is presented in section C of this Fact Sheet.

Specific terms and conditions of this permit (Condition XIII.) are discussed as follows:

- (A) This condition specifies the emissions-related equipment that is allowed to be installed under this construction permit. Per Title 129, Chapters 17 and 19, OPPD is required to obtain a construction permit from the Department.
- (B) Operational and Fuel Limitations:
 - (1) Places fuel and operation limitations on NCS Unit 2 and associated equipment. Dispersion modeling and BACT decisions were based on these requirements.
 - (2) High efficiency mist (drift) eliminators are required as BACT on the new cooling tower. This will help limit PM₁₀ emissions from the cooling tower and ensure compliance with Title 129, Chapter 20.
 - (3) This is the standard permit language for the proper operation of baghouses. This condition requires the use of baghouse dust collectors (DC) at several new and existing emission points. Operation of DCs at existing emission points is required to demonstrate compliance with Chapters 4, 19 (PSD increment modeling), and 20.
 - (4) This condition requires the source to have a broken bag detector on the Unit 2 baghouse. Broken bag detectors provide additional monitoring to verify proper operation of the baghouse in accordance with BACT.
- (C) Stack Dimensions: This condition specifies the stack height and stack cross-section dimensions, upon which the dispersion modeling analysis is based. If any stack exit point dimensions differ from the information used in modeling for the basis of this permit (Table 3), the permittee shall provide a discussion of the discrepancy with respect to modeling issues and submit justification as to why the modeling analysis remains valid with supporting conclusions, or submit revised modeling based on the as-built stack parameters. The Department may require that the project be remodeled to demonstrate compliance with 40 CFR 52.21(k).
- (D) Emission limitations:
 - (1) This condition specifies the numerical emission limitations for equipment approved under this permit. Chapter 4 provides the basis for requiring limits on the existing Unit 1

related equipment (EP 109, 110). Chapter 19 provides the basis for the emission limits on EP 201, 202, 203, 204, 211, 215, and existing equipment (EP 105 and 106) shown in Table 4. Chapter 27 provides the basis for the emission limits on Hg and HCl for EP 201.

- (2) Provides an 18-month period of time to demonstrate compliance with the NO_x limit in Table 4 of the permit. The ability of an SCR system to remove NO_x down to 0.07 lb/MMBtu from a utility boiler burning PRB coal has not been consistently achieved in practice. For this reason, the source is given a “demonstration period” to allow for “tuning” of the SCR system after Unit 2 boiler startup. This condition requires up-front system planning, operation, and recordkeeping and allows for revision of the emission limit if necessary based on operational data from this and other similar boilers/SCR systems. The source may petition the Department for a longer period of time if the source is unable to operate the boiler or SCR system for extended periods of time due to startup-related malfunctions or breakdowns.
 - (3) Outlines the statewide opacity emissions limit (less than 20% opacity) provided under Title 129, Chapter 20, Section 004. Note that this limit is more stringent than the opacity limits specific to the NCS Unit 2 main and auxiliary boilers from 40 CFR 60, Subpart Da and Db. Chapter 20, Section 006 exempts units from Section 004 if they are subject to other opacity standards such as an NSPS. Emission points 105 & 106 are subject to Subpart Y (NSPS), but they are not specifically excluded from the Chapter 20 opacity requirement because the NSPS opacity limit is the same as the Chapter 20 limit.
 - (4) Startup, shutdown, and malfunction requirements in accordance with Chapter 35.
- (E) Notifications: reflects the NSPS requirements per 40 CFR 60, Subpart A (General Provisions) and as referenced by Title 129, Chapter 18, Section 001.01
- (F) Testing Requirements:
- (1) Table 5 lists the performance testing that is required to demonstrate compliance with various state and federal regulations. If approved by EPA, CEMS may be used after certification to demonstrate compliance with the NO_x and SO₂ BACT limits. Performance testing shall be done at 100% load unless otherwise approved by the Department. Specific testing methods shall be in accordance with (F)(4).
 - (2)-(5) This requirement lists the testing schedules and procedures necessary to satisfy the testing requirements of Condition XIII.(F). Applicable testing requirements include 40 CFR 60.48a, 60.46b, and 40 CFR 60.8.
 - (6) Description of mercury testing/monitoring requirements. EPA proposed two methods of demonstrating compliance with the 12-month rolling average Hg limit in the Utility MACT. Although this performance specification (CEMS) and test method (Method 324) have not been approved, it is expected that EPA will have promulgated these test methods/specifications (or related proposals for Hg measurement) before Unit 2 begins operating.
- (G) Monitoring Requirements:
- (1) Lists the CEMS requirements for the Unit 2 boiler. The monitoring system shall be used for measuring and demonstrating compliance with the SO₂, NO_x, and CO emission limitations and opacity listed in Condition XIII.(D)(1), and to meet Acid Rain monitoring requirements. The inlet SO₂ CEMS is required in accordance with 40 CFR 60.47a(b)(1).

- (H) Reporting:
- (1) This condition lists the required reporting with respect the planning and progress of the SCR system for NOx emissions control.
 - (2)-(4) Lists reporting requirements applicable to the facility under 40 CFR 60.7, 60.49a, 60.49b and 40 CFR 75. The reporting requirements include reports of excess emissions, malfunctions, and miscellaneous permit-related correspondence.
- (I) Recordkeeping: Conditions (1) through (4) list recordkeeping requirements. These records shall be readily accessible to state and/or EPA inspectors to review compliance status of the facility. These records must be kept on file at the site for a minimum of five years from the date of the record.
- (J) Acid Rain Requirements: states that the facility shall comply with applicable portions of the Acid Rain Program.
- (K) OPPD has stated that the existing aux boiler currently serving Unit 1 will be taken out of service, therefore the NAAQS and PSD increment compliance modeling analysis was completed without this emission source.

STATUTORY OR REGULATORY PROVISIONS ON WHICH PERMIT REQUIREMENTS ARE BASED:

Applicable regulations: Title 129 - Nebraska Air Quality Regulations as amended February 7, 2004.

PROCEDURES FOR FINAL DETERMINATION WITH RESPECT TO THE PROPOSED CONSTRUCTION PERMIT:

The public notice, as required under NAQR Chapter 14, shall be published on December 30, 2004. Persons or groups shall have 30 days from that issuance of public notice (January 29, 2005) to provide the NDEQ with any written comments concerning the proposed permit action and/or to request a public hearing, in accordance with NAQR Chapter 14. If a public hearing is granted by the Director, there will be a notice of that meeting published at least 30 days prior to the hearing. Persons having comments or requesting a public hearing may contact:

W. Clark Smith-Permitting Section Supervisor
Air Quality Division
Nebraska Department of Environmental Quality
PO Box 98922
Lincoln, Nebraska 68509-8922

If no public hearing is requested, the permit may be granted at the close of the 30-day comment period. If a public hearing is requested, the Director of the NDEQ may choose to extend the date on which the permit is to be granted until after that public hearing has been held. During the 30-day comment period, persons requiring further information should contact:

Bradley W. Reid, P.E.-Construction Permitting Unit Supervisor
Air Quality Division-Permitting Section
Nebraska Department of Environmental Quality
PO Box 98922
Lincoln, Nebraska 68509-8922

Telephone inquiries may be made at:

(402) 471-2189

TDD users please call 711 and ask the relay operator to call us at (402) 471-2186.

**Attachment A
Nebraska City Station Unit 2**

Unit #2 Boiler - Potential to Emit from Coal Combustion
(Pages 1 through 4)

Sub-bituminous, pulverized coal, dry bottom boiler: SCC 1-01-002-22						
Hours	Net Power Output (MW)	Gross Power Output (MW)	Heating Content (Btu/lb)	Maximum Heat Input MMBtu/hr	Maximum Fuel Input (ton/hr)	Fuel Use (ton/yr)
8,760	660	720	8,350	6,478	388	3,398,041

Unit #2 Regulated Air Pollutants	CAS#	Emission Factor	Units	Pollutant Emissions		Control Efficiency %	Controlled Pollutant Emissions	
				lb/hr	TPY		lb/hr	TPY
Nitrogen Oxides (NO _x) ^a	10102-43-9	0.07	lb/MMBtu	453.5	1,986		453.5	1,986
Sulfur Dioxide (SO ₂) ^a	7446-09-5	0.095	lb/MMBtu	615.4	2,695		615.4	2,695
Carbon Monoxide (CO) ^a	630-08-0	0.16	lb/MMBtu	1036.5	4,540		1036.5	4,540
Particulate Matter (PM) ^a	-	0.018	lb/MMBtu	116.6	510.7		116.6	510.7
Particulate Matter < 10 Microns (PM ₁₀) ^a	-	0.018	lb/MMBtu	116.6	510.7		116.6	510.7
Volatile Organic Compounds (VOC) ^a	-	0.0034	lb/MMBtu	22.03	96.5		22.03	96.5
Sulfuric acid mist (aerosol H ₂ SO ₄) ^a	7664-93-9	0.0042	lb/MMBtu	27.21	119.2		27.21	119.2
Fluorides (as HF) ^a	7664-39-3	0.0004	lb/MMBtu	2.59	11.3		2.59	11.3
Lead ^{fg}	7439-92-1	0.007	lb/ton	2.72	11.9	99.00%	0.027	0.119
Mercury ^h	7439-97-6	1.80E-05	lb/MWh	0.013	0.06		0.013	0.057

**Attachment A
Nebraska City Station Unit 2**

Hazardous Air Pollutants	CAS#	Emission Factor (lb/ton)	Uncontrolled Pollutant Emissions		Control Efficiency	Controlled Pollutant Emissions	
			lb/hr	TPY	%	lb/hr	TPY
Acetaldehyde ^c	75-07-0	5.70E-04	0.221	0.9684	0.0%	0.221	0.968
Acetophenone ^c	98-86-2	1.50E-05	0.006	0.0255	0.0%	0.006	0.025
Acrolein ^c	107-02-8	2.90E-04	0.112	0.4927	0.0%	0.112	0.493
Benzene ^c	71-43-2	1.30E-03	0.504	2.2087	0.0%	0.504	2.209
Benzyl chloride ^c	100-44-7	7.00E-04	0.272	1.1893	0.0%	0.272	1.189
Bis(2-ethylhexyl)phthalate (DEHP) ^c	117-81-7	7.30E-05	0.028	0.1240	0.0%	0.028	0.124
Bromoform ^c	75-25-2	3.90E-05	0.015	0.0663	0.0%	0.015	0.066
Carbon disulfide ^c	75-15-0	1.30E-04	0.050	0.2209	0.0%	0.050	0.221
2-Chloroacetophenone ^c	532-27-4	7.00E-06	0.003	0.0119	0.0%	0.003	0.012
Chlorobenzene ^c	108-90-7	2.20E-05	0.009	0.0374	0.0%	0.009	0.037
Chloroform ^c	67-66-3	5.90E-05	0.023	0.1002	0.0%	0.023	0.100
Chlorine (assume all Cl converted to HCl) ^c	7782-50-5	0.0008				5.182	22.70
Cumene ^c	98-82-8	5.30E-06	0.002	0.0090	0.0%	0.002	0.009
Cyanide ^c	57-12-5	2.50E-03	0.970	4.2476	0.0%	0.970	4.248
2,4-Dinitrotoluene ^c	121-14-2	2.80E-07	0.000	0.0005	0.0%	0.000	0.000
Dimethyl sulfate ^c	77-78-1	4.80E-05	0.019	0.0816	0.0%	0.019	0.082
Ethylbenzene ^c	100-41-4	9.40E-05	0.036	0.1597	0.0%	0.036	0.160
Ethyl chloride ^c	75-00-3	4.20E-05	0.016	0.0714	0.0%	0.016	0.071
Ethylene dichloride ^c	107-06-2	4.50E-05	0.017	0.0765	0.0%	0.017	0.076
Ethylene dibromide ^c	106-93-4	1.20E-06	0.000	0.0020	0.0%	0.000	0.002
Formaldehyde ^c	50-00-0	2.40E-04	0.093	0.4078	0.0%	0.093	0.408
Hexane ^c	110-54-3	6.70E-05	0.026	0.1138	0.0%	0.026	0.114
Isophorone ^c	78-59-1	5.80E-04	0.225	0.9854	0.0%	0.225	0.985
Methyl bromide ^c	74-83-9	1.60E-04	0.062	0.2718	0.0%	0.062	0.272

Attachment A
Nebraska City Station Unit 2

Hazardous Air Pollutants	CAS#	Emission Factor (lb/ton)	Uncontrolled Pollutant Emissions		Control Efficiency %	Controlled Pollutant Emissions	
			lb/hr	TPY		lb/hr	TPY
Methyl chloride ^c	74-87-3	5.30E-04	0.206	0.9005	0.0%	0.206	0.900
Methyl ethyl ketone ^c	78-93-3	3.90E-04	0.151	0.6626	0.0%	0.151	0.663
Methyl hydrazine ^c	60-34-4	1.70E-04	0.066	0.2888	0.0%	0.066	0.289
Methyl methacrylate ^c	80-62-6	2.00E-05	0.008	0.0340	0.0%	0.008	0.034
Methyl tert butyl ether ^c	1634-04-4	3.50E-05	0.014	0.0595	0.0%	0.014	0.059
Methylene chloride ^c	75-09-2	2.90E-04	0.112	0.4927	0.0%	0.112	0.493
Naphthalene ^d	91-20-3	1.30E-05	0.005	0.0221	0.0%	0.005	0.022
Phenol ^c	108-95-2	1.60E-05	0.006	0.0272	0.0%	0.006	0.027
Polynuclear Aromatic Hydro. (PAHs) ^d	-	2.08E-05	0.008	0.0353	0.0%	0.008	0.035
Propionaldehyde ^c	123-38-6	3.80E-04	0.147	0.6456	0.0%	0.147	0.646
Tetrachlorethylene (Perc) ^c	127-18-4	4.30E-05	0.017	0.0731	0.0%	0.017	0.073
Toluene ^c	108-88-3	2.40E-04	0.093	0.4078	0.0%	0.093	0.408
1,1,1-Trichloroethane (methyl chloroform) ^c	71-55-6	2.00E-05	0.008	0.0340	0.0%	0.008	0.034
Styrene ^c	100-42-5	2.50E-05	0.010	0.0425	0.0%	0.010	0.042
Vinyl acetate ^c	108-05-4	7.60E-06	0.003	0.0129	0.0%	0.003	0.013
Xylenes ^c	1330-20-7	3.70E-05	0.014	0.0629	0.0%	0.014	0.063
Total PCDD/PCDF ^b	-	2.44E-07	9.46E-05	4.15E-04	0.0%	0.000	0.000
HCl (Hydrochloric acid) ^e	7647-01-0	0.0008				5.182	22.70
HF (Hydrofluoric acid) ^a	7664-39-3	0.0004				2.591	11.349
Metals:							
Antimony ^f	7440-36-0	2.00E-03	0.78	3.40	95.0%	0.039	0.170
Arsenic ^{fg}	7440-38-2	4.00E-03	1.55	6.80	92.0%	0.124	0.544
Beryllium ^{fg}	7440-41-7	6.00E-04	0.23	1.02	97.0%	0.007	0.031
Cadmium ^{fg}	7440-43-9	4.00E-04	0.16	0.68	97.0%	0.005	0.020
Chromium ^{fg}	7440-47-3	1.14E-02	4.42	19.37	97.0%	0.133	0.581

**Attachment A
Nebraska City Station Unit 2**

Hazardous Air Pollutants	CAS#	Emission Factor (lb/ton)	Uncontrolled Pollutant Emissions		Control Efficiency %	Controlled Pollutant Emissions	
			lb/hr	TPY		lb/hr	TPY
Cobalt ^{fg}	7440-48-4	4.86E-03	1.89	8.26	99.0%	0.019	0.083
Lead ^{fg}	7439-92-1	7.00E-03	2.72	11.89	99.0%	0.027	0.119
Manganese ^{fg}	7439-96-5	7.20E-02	27.93	122.33	98.0%	0.559	2.447
Mercury ^h	7439-97-6	3.31E-04	0.13	0.56	89.9%	0.013	0.057
Nickel ^{fg}	7440-02-0	8.00E-03	3.10	13.59	97.0%	0.093	0.408
Selenium ^f	7782-49-2	2.72E-03	1.06	4.62	74.0%	0.274	1.202
					Total HAPs = 55.38		

Notes:

^a NO_x, SO₂, PM/PM₁₀, VOC, H₂SO₄, Fluorides (HF), and CO emission factors based upon BACT analysis

^b Emission factors from AP-42 (09/98), Table 1.1-12

^c Emission factors from AP-42 (09/98), Table 1.1-14

^d Emission factors from AP-42 (09/98), Table 1.1-13

^e HCl emission factor based on case-by-case MACT analysis in accordance with Title 129, Chapter 27 and 40 CFR 63, Subpart B

^f Emission factors calculated using worst-case coal analysis, assuming all metal content is in fly-ash. Assigned control efficiency for antimony is considered conservatively low for baghouse particulate control.

^g Control efficiencies for noted metals are assumed to have some degree of particulate enrichment and control efficiencies were assigned from data obtained from the following website (hard-copy available): www.mtiresearch.com/aecdp/tracelem.html

^h Mercury emission factor based on case-by-case MACT analysis in accordance with Title 129, Chapter 27 and 40 CFR 63, Subpart B Control efficiency under "Metals" section or calculations is estimated from uncontrolled emission rate and permitted limit.

**Attachment A
Nebraska City Station Unit 2**

PTE for Distillate Oil Combustion: Auxiliary Boiler 2

Distillate Oil Combustion (Electric Services): SCC 1-01-005-01						
Hours	Power Output (kW)^a	Horsepower (HP)^a	Heating Value (Btu/gal)	Heat Input MMBtu/hr	Fuel Input (gal/hr)	Fuel Use (MMgal/yr)
500	NA	NA	139,000	125.0	899	0.4

PSD-Regulated Air Pollutants	CAS#	Emission Factor (lb/MMBtu)	Pollutant Emissions	
			lb/hr	TPY
Nitrogen Oxides (NO _x) ^b	10102-43-9	1.71E-01	21.38	5.3
Sulfur Dioxide (SO ₂) ^b	7446-09-5	5.60E-02	7.00	1.8
Carbon Monoxide (CO) ^b	630-08-0	3.57E-02	4.46	1.1
Particulate Matter (PM) ^b	-	2.36E-02	2.95	0.7
Particulate Matter < 10 Microns (PM ₁₀) ^b	-	2.36E-02	2.95	0.7
Volatile Organic Compounds (VOC) ^c	-	5.46E-03	0.68	0.2
Lead (Pb) ^d	7439-92-1	9.00E-06	0.00	0.0
Sulfuric Acid (H ₂ SO ₄) ^b	7664-93-9	2.05E-03	0.26	0.06

Hazardous Air Pollutants (not regulated under PSD rules, per federal CAA)	CAS#	Emission Factor (lb/MMBtu)	Pollutant Emissions	
			lb/hr	TPY
Arsenic ^d	7440-38-2	4.00E-06	0.0005	0.0001
Benzene ^e	71-43-2	1.54E-06	0.0002	0.0000
Beryllium ^d	7440-41-7	3.00E-06	0.0004	0.0001
Cadmium ^d	7440-43-9	3.00E-06	0.0004	0.0001
Chromium ^d	7440-47-3	3.00E-06	0.0004	0.0001
Ethylbenzene ^e	25321-22-6	4.50E-07	0.0001	0.0000
Formaldehyde ^e	50-00-0	2.40E-04	0.0300	0.0075
Lead (Pb) ^d	7439-92-1	9.00E-06	0.0011	0.0003
Manganese ^d	7439-96-5	6.00E-06	0.0008	0.0002
Mercury ^d	7439-97-6	3.00E-06	0.0004	0.0001
Naphthalene ^e	91-20-3	8.10E-06	0.0010	0.0003
Nickel ^d	7440-02-0	3.00E-06	0.0004	0.0001
Polynuclear Aromatic Hydro. (PAHs) ^e	-	8.50E-06	0.0011	0.0003
Selenium ^d	7782-49-2	1.50E-05	0.0019	0.0005
Toluene ^e	108-88-3	4.40E-05	0.0055	0.0014
Xylene ^e	1330-20-7	7.80E-07	0.0001	0.0000
Total HAPs				0.0110

Notes:

- ^a Not applicable.
- ^b Emission factors from AP-42 (09/98), Table 1.3-1 & 1.3-2.
- ^c Emission factors from AP-42 (09/98), Table 1.3-3.
- ^d Emission factors from AP-42 (09/98), Table 1.3-10.
- ^e Emission factors from AP-42 (09/98), Table 1.3-9.

**Attachment A
Nebraska City Station Unit 2**

PTE for Distillate Oil Combustion: Electrical Generator

Distillate Oil Combustion (Electric Services): SCC 2-01-001-02						
Hours	Power Output (kW)	Horsepower (HP)	Heating Value (Btu/gal)	Heat Input MMBtu/hr	Fuel Input (gal/hr)	Fuel Use (MMgal/yr)
500	1,500	1,837	139,000	12.86	93	0.046

PSD-Regulated Air Pollutants	CAS#	Emission Factor (lb/MMBtu)	Pollutant Emissions	
			lb/hr	TPY
Nitrogen Oxides (NO _x) ^a	10102-43-9	3.2	41.15	10.29
Sulfur Dioxide (SO ₂) ^a	7446-09-5	0.05	0.65	0.16
Carbon Monoxide (CO) ^a	630-08-0	0.85	10.93	2.73
Particulate Matter (PM) ^a	-	0.07	0.90	0.22
Particulate Matter < 10 Microns (PM ₁₀) ^a	-	0.057	0.74	0.18
Volatile Organic Compounds (VOC) ^a	-	0.09	1.16	0.29
Lead (Pb) ^b	7439-92-1	negl.	0.00	0.00
Sulfuric Acid (H ₂ SO ₄)	7664-93-9	negl.	0.00	0.00

Hazardous Air Pollutants (not regulated under PSD rules, per federal CAA)	CAS#	Emission Factor (lb/MMBtu)	Pollutant Emissions	
			lb/hr	TPY
Acrolein ^b	107-02-8	7.88E-06	0.0001	0.0000
Acetaldehyde ^b	75-07-0	2.52E-05	0.0003	0.0001
Benzene ^b	71-43-2	7.76E-04	0.0100	0.0025
Formaldehyde ^b	50-00-0	7.89E-05	0.0010	0.0003
Naphthalene ^c	91-20-3	1.30E-04	0.0017	0.0004
Polynuclear Aromatic Hydro. (PAHs) ^c	-	8.20E-05	0.0011	0.0003
Propylene ^b	115-07-1	2.79E-03	0.0359	0.0090
Toluene ^b	108-88-3	2.81E-04	0.0036	0.0009
Xylene ^b	1330-20-7	1.93E-04	0.0025	0.0006
Total HAPs				0.0140

Notes:

^a Emission factors from AP-42 (10/96), Table 3.4-1 & 3.4-2.

^b Emission factors from AP-42 (10/96), Table 3.4-3.

^c Emission factors from AP-42 (10/96), Table 3.4-4.

Attachment A
Nebraska City Station Unit 2

PM / PM10 Emissions From Miscellaneous Dust Collector (Baghouse) Vents

Description	Emission Point	NDEQ ID	Flowrate (acfm)	Grain Loading (gr/cf)	Operating Hours	Potential PM/PM ₁₀ Emissions		
						(lb/hr)	(tpy)	Increase
<i>Existing Equipment</i>								
Unit 1 Econo Ash Storage	103	11-1	5,000	0.02	8,760	0.86	3.75	^a
Unit 1 Fly Ash Silo Exhaust	104a	10-1	5,000	0.02	8,760	0.86	3.75	^a
Unit 1 Fly Ash Silo Exhaust	104b	10-2	2,400	0.02	8,760	0.41	1.80	^a
Tripper System DC	105	9-1	36,000	0.01	8,760	3.09	13.52	6.76 ^b
Tripper System DC	106	9-2	36,000	0.01	8,760	3.09	13.52	6.76 ^b
Neb Ash Fly Ash Storage	107	13-1/2	2,000	0.02	8,760	0.34	1.50	^a
Crusher House DC	109	8-1	34,000	0.0083	8,760	2.41	10.54	5.27 ^b
Crusher House DC	110	8-2	34,000	0.0083	8,760	2.41	10.54	5.27 ^b
Coal Transfer House DC	111	7-1	10,000	0.01	8,760	0.86	3.75	1.88 ^b
<i>New Unit 2 Equipment</i>								
SDA Lime Storage Exhaust	202	24-1	2,000	0.01	8,760	0.17	0.75	0.75
Recycled Ash Storage	203	25-1	3,850	0.01	8,760	0.33	1.45	1.45
Fly Ash Waste Storage Vent	204	23-1	3,850	0.01	8,760	0.33	1.45	1.45
Fly Ash Exhauster	211	23-2	5,000	0.01	8,760	0.43	1.88	1.88
Carbon Silo DC	215	27-1	2,000	0.01	8,760	0.17	0.75	0.75
						Total Increase:	32.21	

^a Calculations are shown for information only since this permit includes the requirement to operate the existing dust collectors, however there is no increase in emissions as a result of the Unit 2 project.

^b There is an increase in utilization of the existing coal handling equipment to accommodate Unit 2, the increase in emissions attributed to Unit 2 is conservatively assumed to equal 1/2 the total potential emissions. (Unit 1 = 410 ton coal/hr, Unit 2 = 388 ton coal/hr)

Example Calculation:

Flowrate = 2,000 cubic feet per minute

Emission Rate/Limit = 0.01 grains per cubic foot

(2,000 cfm) x (60 min/hr) x (0.01 gr/cf) x (1 lb/7000 grains) = 0.17 lb/hr

Attachment A
Nebraska City Station Unit 2

Cooling Tower Particulate Matter Emission Estimates

Assumptions:

Tower Type: Induced Draft Counter Flow

Blowdown Set Point:	7,000	umhos/cm
Liquid Drift Loss:	0.0417	lb/kgal (0.0005% of cooling water)
Cooling Water Flow:	335,000	gpm total
Operation Hours:	8,760	hrs/yr

1.) Water Quality at Blowdown

Set Point (umhos/cm)	TDS (ppm)
7,000	3,500

2.) Circulation Rate

Flow Rate (gpm)	(kgal/hr)
335,000	20,100

3.) Liquid Drift Rate

Liquid Drift (lb/kgal)	PM E.F. (lb/kgal)	PM ₁₀ Fraction ^a	Potential Emissions, total			
			PM Emissions		PM ₁₀ Emissions	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)
0.0417	0.00015	0.45	2.94	12.86	1.32	5.79
		per cell (18 cells)	0.16 lb/hr 0.021 g/sec		0.17 lb/hr 0.021 g/sec	

^a PM/PM₁₀ fraction calculated by interpolation of data provided in "Calculating Realistic PM₁₀ Emissions from Cooling Towers", Joel Reisman and Gordon Frisbie, Abstract No. 216, presented at the 2001 Air & Waste Management Association 94th Annual Conference and Exhibition in Orlando, FL, June 25-28.

**Attachment A
Nebraska City Station Unit 2**

Coal Pile Wind Erosion PM / PM₁₀ Emissions

Assumptions:

Pile shape is like pile configuration B1 from AP-42, Chapter 13.2.5 (01/95)

Surface area of NC2 pile = 32,375 sq. meters

Maximum 2-Minute Wind Speed Calculation:

40.64 mph = 18.2 m/sec Omaha WSFO 1987-91

Storage Pile Contributions

Threshold friction velocity = 1.12 m/sec

Surface Wind Speed Factor (Pile B2)	Surface Wind Speed (U _s)	Friction Velocity U (0.1U _s)	Percent of Pile Area	Pile Size (= 32,375 m ²)
0.2a	3.63	0.363	5%	< friction threshold
0.2b	3.63	0.363	2%	< friction threshold
0.2c	3.63	0.363	29%	< friction threshold
0.6a	10.90	1.090	26%	< friction threshold
0.6b	10.90	1.090	24%	< friction threshold
0.9	16.35	1.635	14%	4,533

Emissions:

$$P = 58(u^* - u_t^*)^2 + 25(u^* - u_t^*)$$

PM

PM-10

0.9:		
P = 58(1.635-1.12) ² + 25(1.635-1.12) =	28.27 g/m ²	14.13 g/m ²
E = 71.28 g/m ² (6,041 m ²)(lb/453.6g) =	282.46 lb/disturbance	141.23 lb/disturbance
Total:	282.46 lb/disturbance	141.23 lb/disturbance
2 complete disturbances per year	564.92 lb/yr	282.46 lb/year
Avg. hours per year = 2,200 hours	0.28 lb/hr	0.14 lb/hr
	1.24 tons/yr	0.62 tons/yr
	0.04 g/sec	0.02 g/sec

Notes:

1. PM₁₀ emissions are assumed to be 0.5(PM emissions)
2. Number of disturbances per year is full pile disturbances, small disturbances are pro-rated to full pile disturbances per year.

**Attachment A
Nebraska City Station Unit 2**

Coal Ash Pile Wind Erosion PM / PM₁₀ Emissions

Assumptions:

Pile shape is like pile configuration B1 from AP-42, Chapter 13.2.5 (01/95)

Surface area of NC2 pile = 242,811 sq. meters

Maximum 2-Minute Wind Speed Calculation:

40.64 mph = 18.2 m/sec Omaha WSFO 1987-91

Storage Pile Contributions

Threshold friction velocity = 0.62 m/sec

Surface Wind Speed Factor (Pile B2)	Surface Wind Speed (U _s)	Friction Velocity U (0.1U _s)	Percent of Pile Area	Pile Size (= 32,375 m ²)
0.2a	3.63	0.363	5%	< friction threshold
0.2b	3.63	0.363	2%	< friction threshold
0.2c	3.63	0.363	29%	< friction threshold
0.6a	10.90	1.090	26%	63,131
0.6b	10.90	1.090	24%	58,275
0.9	16.35	1.635	14%	33,994

Emissions:

$$P = 58(u^* - u_t^*)^2 + 25(u^* - u_t^*)$$

PM

PM-10

0.6a + 0.6b:

$$P = 58(1.09 - 0.62)^2 + 25(1.09 - 0.62) =$$

$$24.57 \text{ g/m}^2$$

$$12.29 \text{ g/m}^2$$

$$E = 9.12 \text{ g/m}^2 (11,219 \text{ m}^2 + 10,356 \text{ m}^2)(\text{lb}/453.6\text{g}) =$$

$$6575.65 \text{ lb/disturbance}$$

$$3287.83 \text{ lb/disturbance}$$

0.9:

$$P = 58(1.635 - 0.62)^2 + 25(1.635 - 0.62) =$$

$$85.14 \text{ g/m}^2$$

$$42.57 \text{ g/m}^2$$

$$E = 71.28 \text{ g/m}^2 (6,041 \text{ m}^2)(\text{lb}/453.6\text{g}) =$$

$$6380.85 \text{ lb/disturbance}$$

$$3190.43 \text{ lb/disturbance}$$

Total:

$$12,956.50 \text{ lb/disturbance}$$

$$6,478.25 \text{ lb/disturbance}$$

percent disturbed per day = 0.5%

$$64.78 \text{ lb/day}$$

$$32.39 \text{ lb/day}$$

hours disturbed per day = 24 hours

$$2.70 \text{ lb/hr}$$

$$1.35 \text{ lb/hr}$$

$$11.82 \text{ tons/yr}$$

$$5.91 \text{ tons/yr}$$

$$0.34 \text{ g/sec}$$

$$0.17 \text{ g/sec}$$

Notes:

1. PM₁₀ emissions are assumed to be 0.5(PM emissions)

Attachment A
Nebraska City Station Unit 2

AP-42 Emission Calculations for Miscellaneous Material Handling. Chapter 13.2.4 (01/95)

Assumptions:

Coal delivery, 1-train/day:	10,000 tons/day	416.7 tons/hr
Coal pick-up, bucket wheel:	9,310 tons/day	388 tons/hr
Coal pile dumping:	9,310 tons/day	388 tons/hr
Ash load-out (max 7.5% ash):	698.2 tons/day	29.1 tons/hr
Ash pile dumping (365 day/yr):	698.2 tons/day	29.1 tons/hr
Average wind speed (U):	11.36 mph	
Average coal moisture (M):	15 %	
Average ash moisture (M):	10 %	
PM multiplier (k):	0.74	
PM ₁₀ multiplier (k):	0.35	

Emission Calculations:

$$E \text{ (lb/ton)} = k(0.0032)(U/5)^{1.3}/(M/2)^{1.4}$$

	PM			PM ₁₀		
	lb/ton	lb/hr	tpy	lb/ton	lb/hr	tpy
Coal Delivery	0.0004	0.171	0.75	0.0002	0.081	0.35
Coal Pick-up	0.0004	0.159	0.70	0.0002	0.075	0.33
Coal Pile Dumping	0.0004	0.159	0.70	0.0002	0.075	0.33
Ash Loadout	0.0007	0.021	0.09	0.0003	0.010	0.04
Ash Pile Dumping	0.0007	0.021	0.09	0.0003	0.010	0.04
	Total:	2.32		Total:	1.10	

STATE OF NEBRASKA



DEPARTMENT OF ENVIRONMENTAL QUALITY

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Mike Johanns

Governor

RE: NOTICE OF DECISION

Omaha Public Power District

444 South 16th Street

Omaha, Nebraska 68102-2247

(Nebraska City Station-Facility #58343)

To Whom It May Concern:

The Department has considered all comments received and has made a final decision to modify and issue the Construction Permit for the above referenced facility. This Permit approves the installation of one 660-megawatt coal-fired electric generating unit (Nebraska City Station Unit 2) in accordance with regulations contained in Title 129 - Air Quality Regulations.

The decision regarding issuance of this Construction Permit may be appealed under Neb. Rev. Stat. 81-1509. This appeal shall be done in accordance with the Administrative Procedure Act, Neb. Rev. Stat. Section 84-901 to 84-920 and Title 115 - Rules of Practice and Procedure.

In preparing this summary, the Department reviewed all comments made during the public comment period from December 30, 2004 through January 29, 2005. Questions and comments related to the issuance of this air permit are summarized in the attached Responsiveness Summary. The Responsiveness Summary consists of four sections:

Comment #: The comment or question topic is summarized.

Response and Rationale: Department's response to the comment raised and the rationale.

Changes: Any changes to the Permit and/or Fact Sheet are addressed.

Applicable Regulations/Statutes: This is a listing of regulations/statutes pertinent to the comment.

The Department appreciates the time and the conscientious efforts of all that have commented. If you have any questions, please contact Brad Reid or me at (402) 471-2189.

Sincerely,

March 9, 2005

Shelley Kaderly, Air Administrator
Air Quality Division

Date

Enclosure

RESPONSE TO PUBLIC COMMENTS SUMMARY
On the Issuance of a PSD Construction Permit for
OPPD-Nebraska City Station Unit 2 (Facility #58343)

Background Information:

Omaha Public Power District (OPPD) currently operates the Nebraska City Station (NCS) with an existing nominal 650 megawatt (MW) coal-fired electric generating unit (Unit 1) located approximately 5 miles southeast of Nebraska City. The Department received a Prevention of Significant Deterioration (PSD) Construction Permit application on February 23, 2004 for the addition of a new 660 MW coal-fired electric generating unit (Unit 2). This permit approves the installation of Unit 2 and associated support equipment.

During the public comment period, EPA Region VII in Kansas City submitted comments. The following are NDEQ's responses to the comments received during the public comment period:

COMMENT #1:

We believed the Best Available Control Technology (BACT) limit for SO₂ is too high. The permit bases the BACT limit on 90% control and assumes a coal with a sulfur content that results in an uncontrolled emission rate of 1.0 lb/MMBtu. However, coals that OPPD are likely to purchase will have actual uncontrolled SO₂ emissions less than 1.0 lb/MMBtu. A discussion of the uncontrolled SO₂ emissions, that are likely from the coal OPPD plans to purchase, is in a June 30, 2004 comment letter on the City Utilities of Springfield Southwest Power Station Unit 2. The PSD application also provides some information on the sulfur content of coals in Appendix C. The highest sulfur content on their table is 0.42%. This would result in uncontrolled SO₂ emissions of 0.83 lb/MMBtu. As you can see from this analysis, a limit of 0.10 lb/MMBtu is not BACT since it allows the FGD to operate below its potential SO₂ collection efficiency. To assure the permit requires BACT over a wide variety of coals, we suggest setting an SO₂ percent reduction requirement and requiring OPPD to install, operate, maintain, and quality assure inlet SO₂ CEMS, as well as the required stack CEMS. Since NSPS Subpart Da already requires these CEMS, it should not be an imposition to include in the permit. An alternative to a percent reduction requirement would be to create BACT limits for various ranges of SO₂ inlet concentrations.

RESPONSE AND RATIONALE:

Based on the maximum average coal analysis presented in Appendix C (0.42%) of the permit application, uncontrolled emissions from Unit 2 would be:

$$0.42\%S \rightarrow \frac{0.0042 \text{ lb} \cdot S}{\text{lb} \cdot \text{Coal}} \times \frac{\text{lb} \cdot \text{Coal}}{0.0085 \text{ mmBtu}} \times \frac{64 \text{ lb} \cdot \text{SO}_2}{32 \text{ lb} \cdot S} \rightarrow 1.0 \frac{\text{lb} \cdot \text{SO}_2}{\text{mmBtu}}$$

The BACT analysis concludes that a spray dryer absorber (SDA) system can consistently achieve a 90% control efficiency when operating with an inlet SO₂ concentration of 1.0 lb/mmBtu, resulting in a controlled SO₂ emission rate of 0.1 lb/mmBtu.

EPA's comment implies that a minimum control efficiency of 90% can be maintained at any inlet SO₂ concentration. This is definitely not the case. As inlet SO₂ concentration decreases, it becomes more difficult to reach a given percent removal efficiency. Pushing an SDA system beyond its design capabilities (working harder at lower inlet SO₂ concentrations) leads to decreased reliability and permit compliance problems. Similarly, constructing an oversized SDA system would cost far more to build and operate than SDA systems on comparable facilities. In light of the BACT decision regarding the

RESPONSE TO PUBLIC COMMENTS SUMMARY
On the Issuance of a PSD Construction Permit for
OPPD-Nebraska City Station Unit 2 (Facility #58343)

referenced permit (Southwest Power Station Unit 2), the SO₂ BACT emission limit for this permit was lowered to 0.095 lb/mmBtu to be equal to, or less than, all area PRB coal-fired utility boilers.

Additionally, in terms of compliance margin, it must be remembered that an SDA system requires periodic change-out of the atomizers that inject the lime slurry mist into the exhaust stream. These atomizers are changed-out “on-the-fly,” typically every 3-4 months, in a period of 3-4 hours. These hours will not be removed from its 30-day rolling average SO₂ emissions computation. To allow for higher SO₂ emissions during such periods, OPPD will need to make up for these higher emissions by attaining additional compliance margin for the rest of the 30-day period. Thus, it is important that the compliance margin not be minimized to the extent that it creates a potential for the needed, regular, maintenance activities to cause a noncompliance situation. The permit has been clarified, however, that the 30-day rolling average limit for SO₂ emissions does not apply during periods of startup, shutdown, and malfunction (SSM). Emissions during these periods may be removed from the emission computation of the 30-day rolling average for SO₂. Annual emission records must still include emissions during periods of SSM.

It is also important to note that only limited emissions data exists demonstrating the capabilities of an SDA system for controlling emissions from a similar type and size of utility boiler burning PRB coal. This SO₂ emissions data (from KCP&L’s Hawthorn plant) show that the SDA system has not achieved emission rates below 0.1 lb/mmBtu on a consistent basis.

EPA also suggests setting an SO₂ percent reduction requirement. Effectively, this would make the BACT limit a “percent removal” value as opposed to (or in addition to) a “lb/mmBtu” value. This would be at odds with all of the recent BACT limits for SO₂ at other facilities nationwide. These limits at other facilities have been stated on a lb/mmBtu basis, and with good reason, as explained earlier about the difficulties of achieving a consistent percent removal under varying inlet conditions.

Regarding inlet SO₂ monitoring, an inlet SO₂ continuous emissions monitoring system (CEMS) has been added to the permit to demonstrate compliance with the New Source Performance Standards (NSPS) under 40 CFR 60, Subpart Da, which contains a 70% SO₂ reduction requirement.

CHANGES:

Fact sheet was updated to reflect the lower SO₂ limit, SSM provisions for the 30-day SO₂ limit, and inlet SO₂ CEMS requirement.

Permit Condition XIII.(D)(1), Table 4 was changed decrease the 30-day SO₂ limit for the Unit 2 boiler and to specify that this limit does not apply during periods of SSM.

Permit Condition XIII.(G)(1) was changed to require an SO₂ CEMS for the inlet of the Unit 2 boiler control equipment in accordance with 40 CFR 60.47a(b)(1).

Permit Condition XIII.(I)(3)(h) was changed to clarify that records of SSM shall be in accordance with 40 CFR 60.7(b) and Chapter 35.

RESPONSE TO PUBLIC COMMENTS SUMMARY
On the Issuance of a PSD Construction Permit for
OPPD-Nebraska City Station Unit 2 (Facility #58343)

APPLICABLE REGULATIONS:

Title 129, Chapter 18 – New Source Performance Standards; Chapter 19 – Prevention of Significant Deterioration of Air Quality; Chapter 34 – Emission Sources; Testing, Monitoring; Chapter 35 – Compliance Exceptions Due to Startup, Shutdown, or Malfunction.

COMMENT #2:

We recommend the permit contain the number of runs per test, minimum test time, and minimum test volume in Condition XIII.(F). We also recommend that NDEQ require Method 201 or 201A and Method 202 instead of Method 5 and Method 202 for the PM₁₀ testing. Our hope is to get permitting authorities to use these test methods to make the test results and permit limits easier to compare.

RESPONSE AND RATIONALE:

The Department requires test parameters, including the number of test runs, minimum test time, and minimum test volumes, to be submitted as part of the test protocol requirements of Condition XIII.(F)(2). However, to further clarify testing requirements within the permit, the Department has modified Table 4 to include requirements for three test runs which is consistent with general practice and 40 CFR 60.8. The Department applauds EPA for addressing the issue of PM₁₀ emissions from coal-fired boilers, and specifically by asking for Method 202 testing for condensable (back-half) particulates. The overwhelming majority of particulate measured downstream of the fabric filter will indeed be PM₁₀, with very little particles greater than 10 micrometers in size. Since the New Source Performance Standard (NSPS), Subpart Da requires performance testing for PM (not PM₁₀), the Department has chosen to keep the requirement for PM testing using Methods 5 and 202.

CHANGES:

Permit Condition XIII.(D)(1), Table 4 was modified to clarify that “test method average” was the average of three (3) test runs.

Permit Condition XIII.(F)(4) was clarified to indicate that alternate test methods must be approved in writing by the Department.

APPLICABLE REGULATIONS:

Title 129, Chapter 18 – New Source Performance Standards; Chapter 19 – Prevention of Significant Deterioration of Air Quality; Chapter 34 – Emission Sources; Testing, Monitoring.

COMMENT #3:

We suggest the Nebraska Department of Environmental Quality (NDEQ) revise XIII(I)(3)(d) to require OPPD to send NDEQ a copy of the vendor-guaranteed maximum total liquid drift.

RESPONSE TO PUBLIC COMMENTS SUMMARY
On the Issuance of a PSD Construction Permit for
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RESPONSE AND RATIONALE:

A copy of the vendor's liquid drift guarantee will be sent to the Department upon vendor selection for the cooling tower.

CHANGES:

Permit Condition XIII.(I)(3)(d) was modified to also require submittal of vendor guarantee.

APPLICABLE REGULATIONS:

Title 129, Chapter 4 – Ambient Air Quality Standards and Title 129, Chapter 19 – Prevention of Significant Deterioration of Air Quality.

COMMENT #4:

NDEQ needs to revise Condition XIII.(E) to require the notification for the Stationary Reciprocating Internal Combustion Engines rule as required by 40 CFR 63.6590(b).

RESPONSE AND RATIONALE:

Permit was revised by adding notification requirement for consistency with how other notification requirements are handled in the permit. The Fact Sheet accompanying the Permit already mentions the need for initial notification of the engine in accordance with 40 CFR 63.6590(b).

CHANGES:

Permit Condition XIII.(E)(5) was added to specify notification requirements for emergency generator.

APPLICABLE REGULATIONS:

Title 40 – Code of Federal Regulations, Part 63, Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Questions regarding this summary may be directed to:

Air Quality Division-Permitting Section
Nebraska Department of Environmental Quality
PO Box 98922
Lincoln, NE 68509-8922