Attachment 3

Otter Tail Power Company's Application, Revised filing and Informational filing for Advance Determination of Prudence in North Dakota

OTTERTAIL
CORPORATION

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May 20, 2011

Reply to Fergus Falls office
Direct: 218-998-7152

Mr. Darrell Nitschke
Director of Administration/Executive Secretary
North Dakota Public Service Commission
State Capitol
600 East Boulevard Dept. 408
Bismarck, ND 58505

RE: In the Matter of Otter Tail Power Company's Application for an Advance Determination of Prudence for its Big Stone Air Quality Control System Project

Dear Mr. Nitschke:

Enclosed are an original and seven copies of Otter Tail's application along with a check in the amount of $125,000 for the filing fee. The application and cover letter are being sent to you by electronic mail as well as UPS overnight mail delivery.

Also enclosed are an original and seven copies of Otter Tail's Application for Trade Secret Protection. This also is sent to you by electronic mail and UPS overnight mail delivery.

The North Dakota Legislature recently passed House Bill 1221, and it was signed into law by Governor Dalrymple. HB 1221 amends the existing advance determination of prudence statute, N.D. Century Code § 49-05-16. While HB 1221 does not become law until August 1, 2011, Otter Tail has no objection to having its application subject to the statutory revisions called for by HB 1221.

Thank you for your attention to this matter. Please feel free to contact me if you have any questions.

Sincerely,

/s/ MARK B. BRING

Mark B. Bring
Associate General Counsel

MBB:nlo
By electronic filing
Enclosures (as stated)

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF NORTH DAKOTA

IN THE MATTER OF OTTER TAIL POWER COMPANY'S APPLICATION FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR ITS BIG STONE AIR QUALITY CONTROL SYSTEM PROJECT	)))))))	**CASE NO. PU-11-____**

APPLICATION FOR TRADE SECRET PROTECTION

Pursuant to N.D. Admin. Code § 69-02-09-01, Otter Tail Power Company ("Otter Tail") respectfully requests that the Commission issue a trade secret protective order under N.D. Admin. Code § 69-02-09-04. The purpose of the requested protective order is to protect against public disclosure of trade secrets as defined by N.D. Cent. Code § 47-25.1-01(4).

The information for which Otter Tail seeks trade secret protection are the following attachments to the Application for an Advance Determination of Prudence filed on May 20, 2011:

- Attachment No. 4 – SO_2, NO_x, and Mercury Reduction Study
- Attachment No. 5 - Big Stone Plant AQCS Project Cost Estimate
- Attachment No. 6 - Big Stone AQCS Project Operating and Maintenance Cost Calculations
- Attachment No. 8 – Natural Gas Conversion Conceptual Study
- Attachment No. 9 – Otter Tail Power Company BSP Pro Forma Results Letter Report North Dakota

The above-referenced information is not publicly available and is confidential business information. The information was prepared specifically for Otter Tail with data inputs unique to Otter Tail, pursuant to agreements that require the continuing confidentiality of the information. Furthermore, the information cannot be selectively disclosed without violating the public reporting requirements of the Securities and Exchange Commission. The information, therefore, is not readily ascertainable by proper means by other persons.

Vendors and competitors would have an opportunity to obtain economic value from disclosure or use of the information, to the detriment of Otter Tail and the customers we serve. If publicly available, vendors could use the information to their advantage in competing for project procurement opportunities, while competitors could use the information to leverage their rate positions in the marketplace to Otter Tail's detriment.

In accordance with N.D. Admin. Code § 69-02-09-02, one copy of the trade secret material is provided in the enclosed sealed envelope labeled TRADE SECRET – PRIVATE.

Respectfully submitted this 20th day of May 2011.

OTTER TAIL POWER COMPANY

By *<u>/s/ MARK BRING</u>*

Mark Bring
Associate General Counsel
Otter Tail Corporation
215 South Cascade Street, PO Box 496
Fergus Falls, MN 56538-0496
Telephone No. (218) 998-7152

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF NORTH DAKOTA

IN THE MATTER OF OTTER TAIL POWER COMPANY'S APPLICATION FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR ITS BIG STONE AIR QUALITY CONTROL SYSTEM PROJECT	)))))))	**CASE NO. PU-11-____**

APPLICATION FOR AN ADVANCE DETERMINATION OF PRUDENCE

Otter Tail Power Company (Otter Tail or Applicant), makes this Application pursuant to NDCC § 49-05-16 and NDAC § 69-02-02-04, for an advance determination that the addition of the air quality control system (AQCS) at the Big Stone Generating Station, to comply with the Federal Clean Air Act and the South Dakota Regional Haze Implementation Plan (SD Haze SIP), is reasonable and prudent.

I.

That Applicant's full name and post office address are:

Otter Tail Power Company
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496

II.

That Applicant is a Minnesota corporation duly authorized to do business in the State of North Dakota as a foreign corporation, and that it is doing business in the State of North Dakota as a public utility subject to the jurisdiction of and regulation by the North Dakota Public Service Commission (Commission) under NDCC Title 49 as amended.

III.

Applicant's Certificate of Incorporation and Amendments thereto have been previously filed with the Commission. Such Certificate and Amendments are hereby incorporated by reference, as though fully set forth herein. A Certificate of Good Standing is attached.

IV.

That the Big Stone Generating Plant (Big Stone or Plant) is a 475 megawatt (MW) coal-fired power plant located near Milbank, South Dakota. The Plant became operational in 1975 and burns low sulfur sub-bituminous coal using a cyclone-fired boiler. Big Stone is jointly owned by three utilities: Otter Tail (53.9%), NorthWestern Energy (23.4 %), and Montana-Dakota (22.7 %).

V.

That the SD Haze SIP and its implementing rules provide that the Big Stone AQCS be installed, operated and shown to comply as expeditiously as practicable but not later than five years from the United States Environmental Protection Agency's (EPA) approval of the SD Haze SIP submitted to the EPA on January 21, 2011 by the South Dakota Department of Environment and Natural Resources. As a result, if EPA approves the SD Haze SIP in 2011, the Big Stone AQCS must be installed and operational by 2016. To be in compliance by 2016, the AQCS Project design must be finalized and procurement of major elements of the AQCS must be initiated in early 2012. That the estimate of the capital costs to install the AQCS Project at Big Stone is $489,397,400.00 (2015 dollars), +/-20%.

VI.

The EPA recently proposed National Emissions Standards for Hazardous Air Pollutants (HAPs) for Coal-Fired Utilities which would require mercury emissions reductions at the Plant. The rule was proposed on March 16, 2011, and is projected to be final by November 16, 2011. The compliance timeline of the proposed rule requires coal-fired utilities to install mercury controls to comply with the rule's established mercury emission limits by early 2015. The Co-Owners are recommending installation of the mercury control equipment at the time of the AQCS project as the requirement to control mercury emissions is anticipated within the time frame of the AQCS project. Installation of mercury control equipment on the Plant is estimated to cost an additional $5,012,700. Otter Tail's share of the total estimated cost of the AQCS Project including installation of mercury control equipment is approximately $266 million (2015 dollars).

VII.

The Exhibits attached hereto and Otter Tail's Integrated Resource Plan submitted to the Commission on June 25, 2010 (Case No. PU-10-346) with results presented at a Periodic Information Exchange meeting on July 23, 2010, demonstrate the Big Stone AQCS project (and additional mercury control anticipated to be required by March 16, 2011 proposed rule relating to HAPs) is a prudent course of action and the most cost effective option to allow the continued operation of the Big Stone plant beyond 2016. Montana-Dakota is filing a similar application for advance determination of prudence with respect to its participation in the AQCS project as a Co-Owner of the Big Stone Plant. Exhibits 1-3 attached hereto represent exhibits jointly filed by Otter Tail and Montana-Dakota in support of the AQCS project.

VIII.

That the following list of exhibits is attached hereto in support of the Application. A Verification is provided for Joint Exhibits 1-3.

- Joint Exhibit 1- Detailed description of the Big Stone Air Quality Control System Project verified by Mr. Mark Rolfes, Manager, Generation Development.
- Joint Exhibit 2 - Reasonableness of the Big Stone AQCS Project verified by Mr. Mark Rolfes, Manager, Generation Development.
- Joint Exhibit 3 – Assessment of Financial and Operational Impacts of Pending Environmental Regulations to the Big Stone Plant verified by Mr. Mark Rolfes, Manager, Generation Development.

IX.

That Applicant believes it is in the public interest that Applicant be granted an Advance Determination of Prudence to proceed with the installation of the AQCS project (including mercury control anticipated to be required by March 16, 2011 proposed rule relating to HAPs) as more fully described in Exhibit 1, in the time frame required to meet the SD Haze SIP requirements.

WHEREFORE, Applicant respectfully requests that the Commission:

1. Issue Notice of Opportunity for hearing to interested parties and, if no hearing is requested within twenty days, to waive the hearing in accordance with subsection 5 of NDCC §49-02-02;

2. Issue an order determining that the design and installation of the Big Stone AQCS project (including mercury control anticipated to be required by the March 16, 2011 proposed rule relating to HAPs) is reasonable and prudent; and

3. Grant such other relief as the Commission shall deem appropriate.

Dated this 20th day of May 2011.

OTTER TAIL POWER COMPANY

BY *_/s/ MARK ROLFES__________*
Mark Rolfes
Manager Generation Development
215 South Cascade Street, PO Box 496
Fergus Falls, MN 56538-0496
Telephone No. (218) 739-8648

Subscribed and sworn to before me
this 20th day of May 2011.

/s/ WENDI A. OLSON
Otter Tail County, Minnesota
My Commission Expires: 01/31/2015

Of Counsel:

Mark Bring
Associate General Counsel
Otter Tail Corporation
215 South Cascade Street, PO Box 496
Fergus Falls, MN 56538-0496
Telephone No. (218) 998-7152

State of North Dakota

SECRETARY OF STATE

CERTIFICATE OF GOOD STANDING
OF

OTTER TAIL POWER COMPANY

The undersigned, as Secretary of State of the State of North Dakota, hereby certifies that OTTER TAIL POWER COMPANY , a Minnesota corporation, authorized to transact business in the State of North Dakota on February 24, 1914, and according to the records of this office as of this date, has paid all fees due this office as required by North Dakota statutes governing foreign corporations.

ACCORDINGLY the undersigned, as such Secretary of State, and by virtue of the authority vested in him by law, hereby issues this Certificate of Good Standing to

OTTER TAIL POWER COMPANY

Issued: May 18, 2011

Alvin A. Jaeger
Secretary of State

EXHIBITS TO

APPLICATION FOR AN ADVANCE

DETERMINATION OF PRUDENCE

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Attachment 2 -	Assessment of Anticipated Federal and State Environmental Regulations
Attachment 3 -	Administrative Rules of South Dakota Chapter 74:36:21
Attachment 4 -	SO_2, NO_x, and Mercury Reduction Study
Attachment 5 -	Big Stone Plant AQCS Project Cost Estimate
Attachment 6 -	Big Stone AQCS Project Operating and Maintenance Cost Calculations
Attachment 7 -	Contract Strategy Summary
Attachment 8 -	Natural Gas Conversion Conceptual Study
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I. Joint Exhibit 1 - THE BIG STONE AIR QUALITY CONTROL SYSTEM PROJECT

A. Big Stone Plant Description

The Big Stone Plant ("Big Stone" or "Plant") is located in Grant County, South Dakota, 2.5 miles northwest of Big Stone City, South Dakota, which is near the Minnesota/South Dakota border. Big Stone is rated at 495 MW gross and 475 MW net electrical output. The Plant has three owners; Otter Tail Power Company ("OTP") owns 53.9 percent of the Plant, NorthWestern Energy owns 23.4 percent, and Montana-Dakota Utilities Co. ("Montana-Dakota") owns 22.7 percent. The Co-Owners, as investor owned utilities, use the Plant to provide electricity to customers in their South Dakota, North Dakota, Montana and Minnesota service areas. Montana-Dakota and OTP serve North Dakota load. The Plant was built in the early 1970s and began commercial operation on May 1, 1975. Montana-Dakota and OTP request in their Applications that the Commission find prudent Montana-Dakota's and OTP's participation in the AQCS Project. In terms of the joint plant ownership agreement, approval of two of the three owners is needed to decide on whether to proceed with the AQCS Project or any other course of action.

The Plant was constructed and operates as a baseload facility with load following capabilities. Load following is the ability for the unit to adjust its output between full load and partial load to meet the demands of the system.[1] The Plant is a cornerstone generation source for all three companies, comprising the largest baseload resource for each of the Co-Owners. The Plant also provides electricity, steam and water to the adjacent POET Biorefining Ethanol Plant.

The Big Stone Plant has a single generating unit. Its cyclone boiler was originally designed by Babcock & Wilcox to burn lignite fuel. The boiler is a Carolina-type balanced draft pump-assisted radiant unit. The unit was originally constructed with a Westinghouse steam turbine and generator. Through the years, due to maintenance problems and efficiency improvement, certain steam components have been replaced. The generator stator and rotor have been rewound, and the generator shaft was replaced in 1987 due to failure of the original rotor.

The Plant now receives its fuel from Wyoming, transported by the BNSF Railway Company. The Big Stone Plant burns low sulfur PRB fuel to limit sulfur dioxide emissions, but it is not currently equipped with a flue gas desulfurization system for control of sulfur dioxide emissions, commonly referred to as a scrubber. Particulate emissions are controlled by a baghouse, and an over fire air system provides nitrogen oxide control.

The Plant is a zero-liquid discharge facility, meaning that no process water used in Plant operations leaves the site other than through evaporation. Big Stone Lake is the water source for the Plant. Water can only be taken from the lake when lake levels are at or above levels prescribed in water appropriations permits issued by the South Dakota Department of Environment and Natural Resources (South Dakota DENR). The water is stored in a cooling

[1] For example, during certain times of the year the Plant's output will be low at night, as demand is low. The Plant will then increase output in the morning as the system load increases. Late in the evening the Plant will decrease its output as load decreases.

pond for use in the condenser for cooling. The Plant also has an evaporation pond and holding pond for maintaining water quality as well as a brine concentrator used to control water chemistry in the cooling pond.

The Big Stone Plant has a dry on-site ash disposal area permitted by the South Dakota DENR.

B. Requirement to Implement the Big Stone AQCS Project

The federal Clean Air Act established a national goal of remedying any existing and preventing any future impairment of visibility from man-made air pollution in specified "Class I" areas of the United States.[2] EPA promulgated the Regional Haze Rule ("RHR") in 1999 to address visibility impairment in these areas, and in 2005 published a revised rule that provided guidelines for control technology determinations under the RHR.[3] State environmental agencies like the South Dakota DENR and the North Dakota Department of Health (DOH) are required to submit State Implementation Plans ("SIPs") to EPA that develop and implement their strategy to reduce existing emissions that may contribute to regional haze, and to set additional reasonable progress goals toward meeting the goal of no man-made visibility impairment in Class I areas by 2064.[4]

Of the multiple CAA requirements for state regional haze programs, among the most significant requirements is the requirement to procure, install and operate Best Available Retrofit Technology ("BART") on major air emission sources, including existing electric generating units, that were placed into operation between 1962 and 1977.[5] The BART requirement is designed to determine appropriate air pollution control equipment to retrofit major air emission sources that were constructed before the applicability of the New Source Review program in the late 1970s.[6] The Big Stone Plant became operational in 1975 and is among the newer plants subject to the BART requirement.

Because the Big Stone Plant is located in South Dakota, the South Dakota DENR is the agency responsible for developing the SD Haze SIP, which includes the determination of BART emission controls for air emission sources in the state that are subject to the BART requirement. A regional haze SIP includes extensive emission and visibility impact analysis, establishment of goals for reasonable progress in improving visibility, development of a long term strategy, and

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2 42 U.S.C. § 7479 (CAA § 169A).

3 40 C.F.R. §§ 51.300 to 51.309 ("Protection of Visibility") & App. Y ("Guidelines for BART Determinations Under the Regional Haze Rule").

4 For major air emission sources in North Dakota, including electric generating units located in North Dakota, the DOH developed a SIP that determines Best Available Retrofit Technology requirements for multiple facilities, and takes other action to reduce regional haze from North Dakota sources of air pollution.

5 *See* 42 U.S.C. § 7491(b)(2)(A) (CAA § 169A(b)(2)(A)).

6 While emission standards had been applied to electric generating units in other Clean Air Act programs before the late 1970s, the New Source Review program was not yet in place. The New Source Review program initiated the requirement that new major sources of air emissions install Best Available Control technology as part of their construction permit requirements. *See* 42 U.S.C. § 7475(a)(4) (CAA § 165(a)(4)).

determination of BART requirements for individual facilities.[7] The process of preparing the SIP also includes opportunities for public comment, consultation with Federal Land Managers, and review of proposed plans by neighboring states.

At the culmination of work begun in 2007, the DENR determined that Big Stone is both BART-eligible and subject to BART, based upon air dispersion modeling indicating that Big Stone reasonably contributes to visibility impairment in certain Class I areas in South Dakota, North Dakota, Michigan, and Minnesota.[8] The DENR therefore determined that BART must be installed on Big Stone. Section 6.0 of the SD Haze SIP, the section that explains the BART determination made for the Big Stone Plant, is provided as Attachment 1 to this Exhibit.

The Co-owners also assessed other anticipated environmental regulations and the costs that could be expected to be imposed to achieve compliance. That assessment is provided in Attachment 2 to this Exhibit.

Since BART is a case-by-case determination for each unit that is subject to BART, the DENR evaluated available control technology for particulate matter ("PM"), sulfur dioxide ("SO_2") and nitrogen oxides ("NO_X"), based on its technical feasibility, cost, non-air impacts, remaining useful life of the source, and projected reduction of visibility impacts.[9] After considering information on the available control technology options, the DENR assessed the visibility improvement to be expected from the installation of air pollution control technology on the Big Stone Plant, in eight different configurations.[10]

Based on its extensive technical analysis, the South Dakota DENR made a final determination that the following control technology constitutes BART for the Big Stone Plant:

- Selective Catalytic Reduction with Separated Overfire Air ("SCR," "SOFA," and collectively, "SCR/SOFA"), for NO_X, which provides the highest level of control of the control equipment found to be feasible;

7 South Dakota's full SIP contains these elements, and may be found online at: http://denr.sd.gov/des/aq/publicnotices/RegionalHazeSIPDraft.pdf.

8 In 2010 the South Dakota DENR determined that, based on air dispersion modeling results, the Big Stone Plant would be reasonably anticipated to contribute to an impairment of visibility at the following Class I Areas: Badlands National Park in South Dakota, Theodore Roosevelt National Park in North Dakota, Isle Royale National Park in Michigan, and Voyagers National Park and the Boundary Waters Canoe Area in Minnesota. The detailed technical analysis and associated modeling results are fully set forth in the SD Haze SIP, §§ 6.1.3, Otter Tail Power Company-Big Stone I, and 6.2, Otter Tail Power Company's Modeling Results.

9 *Id*. at §§ 6.3.1, Particulate BART Review, 6.3.2, Sulfur Dioxide BART Review, and 6.3.3, Nitrogen Oxide BART Review.

10 *Id*. at § 6.3.4, Visibility Impact Evaluations.

- Semi-Dry Flue Gas Desulfurization (FGD), for SO_2,[11] which provides slightly less than the highest level of SO_2 control of the control equipment found to be feasible, but which SD DENR found to have less visibility impact than the top-ranked option for SO_2, when modeled in combination with the selected NO_X and PM BART controls; and

- Baghouse, for PM, which provides the highest level of control of the control equipment found to be feasible.[12]

The emission limitations represented by installation of the above-listed control technologies on Big Stone were determined to constitute BART, and are required by the SD Haze SIP to be installed and operational as expeditiously as practicable but not later than five years from EPA's approval of the SD Haze SIP. The SD DENR submitted its SD Haze SIP to EPA on January 21, 2011. As part of the SD Haze SIP, South Dakota implemented its BART determination by placing the related emission limitations into its state rules.[13] Administrative Rules of South Dakota Chapter 74:36:21, provided as Attachment 3 to this Application, requires these controls to be installed on existing coal-fired power plants that are subject to BART by establishing the related emission limitations for SO_2, NO_X and PM that reflect the installation of the BART control technology.[14] The Big Stone Plant is the only plant in South Dakota to which this rule applies.[15]

The EPA could require changes in aspects of the SD Haze SIP as part of its review although the EPA has reviewed and provided comments to the South Dakota DENR throughout the development of the SD Haze SIP. EPA's latest comments to the DENR related to the form of the final emission limitations and their associated compliance monitoring requirements, and other parts of the SD Haze SIP not related to the Big Stone AQCS. The EPA did not disagree with the control technology chosen as BART for the Big Stone Plant, and adjustments to the

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11 The most common semi-dry FGD system is the lime Spray Dryer Absorber (SDA) using a baghouse for downstream particulate collection. This Petition addresses the spray dryer FGD process. Two other variations, the Novel Integrated Desulfurization (NIDTM) and Circulating Dry Scrubber are similar technologies that achieve similar levels of control effectiveness. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling. Due to the similar nature of the different semi-dry technologies and the similar levels of control efficiency achieved by all the technologies, semi-dry technologies are grouped together for purposes of this Petition.

12 While the current baghouse represents BART, the baghouse will have to be replaced to accommodate the additional flue gas draft requirements that will be caused by the upstream installation of the semi-dry FGD and SCR/SOFA systems.

13 *See* SD Haze SIP, § 6.4, BART Requirements.

14 S.D. Admin. R. 74:36:21:06, BART Determination for a BART-eligible Coal-fired Power Plant, establishes the emission limitations for particulate, sulfur dioxide and nitrogen oxides. The rules were approved by the South Dakota Board of Minerals and Environment on September 15, 2010, and by the South Dakota Interim Rules Review Committee on November 17, 2010. The rules were filed with the South Dakota Secretary of State on November 17, 2010, and became effective twenty (20) days later, on December 7, 2010.

15 *See* SD Haze SIP, § 6.2, concluding that the Big Stone Plant is "the only source subject to BART in South Dakota."

form of final emission limits and compliance monitoring requirements would be extremely unlikely to change the determination of the control equipment required by the DENR under BART. This is especially the case given that the DENR chose the combination of controls predicted by air dispersion modeling to provide the greatest degree of visibility improvement of the options available.

The comparison of emission limitations in the Big Stone Plant's current South Dakota DENR air quality permit with the emission limitations that represent the DENR's BART determination are shown in Table 1.

Table 1 – Big Stone Emission Limits

	Current Permit	**BART Rule**
SO_2	3.0 lb/mmBtu	0.09 lb/mmBtu
PM_{10}	0.26 lb/mmBtu	0.012 lb/mmBtu
NO_X	0.86 lb/mmBtu	0.10 lb/mmBtu

According to South Dakota DENR's BART determination, the suite of control technologies to be implemented in the Big Stone AQCS reduce emissions to a level at which the Plant would not reasonably contribute to visibility impairment in the Boundary Waters and Voyager's Class I areas in Minnesota, Isle Royale National Park in Michigan, the Badlands National Park in South Dakota, and the Theodore Roosevelt National Park in North Dakota.[16]

C. Detailed Description of the Big Stone AQCS Project

The Big Stone AQCS Project consists of a semi-dry FGD system with a new baghouse, anhydrous-based SCR, SOFA, Activated Carbon Injection ("ACI"), and the associated ancillary balance-of-plant systems. The Plant's Co-Owners have included in the AQCS the design and installation of an ACI for control of mercury emissions in anticipation that such requirements will be imposed by the EPA within the timeframe of the AQCS Project construction schedule.[17] At OTP's request on behalf of the Co-Owners, Sargent & Lundy, LLC ("Sargent & Lundy") conducted a conceptual design study and prepared estimated costs for the AQCS needed to comply with the South Dakota DENR BART determination. The conceptual design is attached to this Exhibit as Attachment 4, and an updated cost estimate is included as Attachment 5. This section of the Exhibit describes the AQCS in detail, while the implementation schedule and cost of the AQCS Project are discussed in the sections that follow.

1. Semi-Dry Flue Gas Desulfurization

The semi-dry FGD system is focused on the control of SO_2 emissions, and includes spray dryer absorbers, a baghouse, lime and recycle preparation, and solid waste handling. The spray dryer absorbers and baghouse are installed on the Plant downstream of the air heater. In a semi-dry

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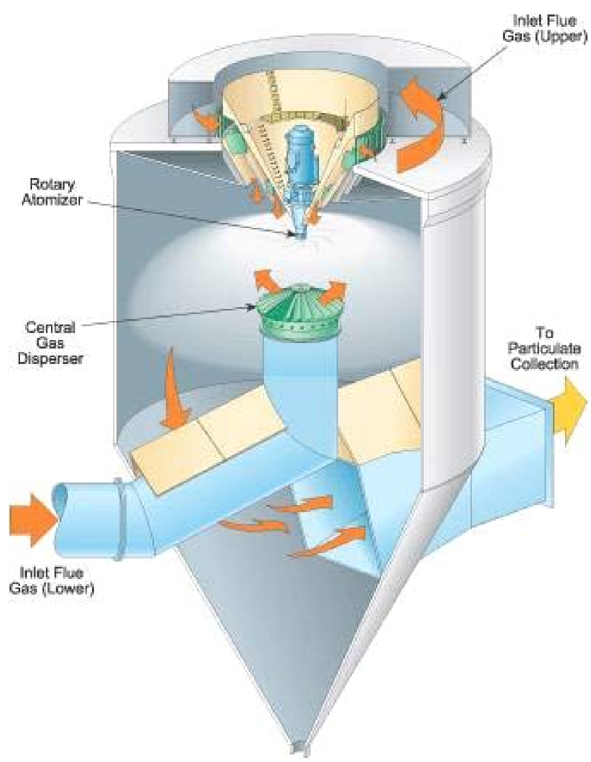
16 *See* SD Haze SIP, § 6.3.4, Visibility Impact Evaluations.

17 Because installation of the ACI system is proceeding in anticipation of the future requirement to control mercury emissions, the ACI system is part of Montana-Dakota's and OTP's requests for an ADP.

FGD system, flue gas is brought into contact with lime slurry in a spray dryer absorber (SDA) vessel. This process uses pebble quicklime (CaO) that must be hydrated before use. Pebble lime is delivered to the Plant site via truck and stored in a silo. Lime would then transfer to a slaker where the hydration (water mixed with lime) occurs. SO_2 absorption takes place in the SDA. Additional SO_2 removal takes place in the baghouse, downstream of the SDA. Calcium reacts with the SO_2 to form two waste solids, sulfate ($CaSO_4$) and sulfite ($CaSO_3$).

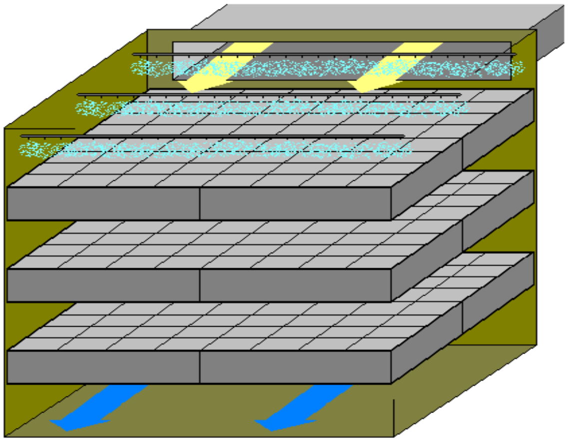
The dried solids are entrained in the flue gas, exit the SDA along with the fly ash from the boiler, and are then collected in a baghouse. Waste collected in the baghouse is pneumatically transported to either a waste storage silo or a recycle silo. The recycle silo is located above the waste slurry preparation area. From the recycle silo, the dry waste flows to a premix tank where it is combined with water. The slurry overflows to a recycle holding tank, which then overflows into a recycle slurry storage tank. This recycle system allows the lime to be passed through the SDA several times, mainly to reduce lime consumption. Semi-dry FGD waste not utilized in the recycle silo will be sent to a waste storage silo then loaded into trucks and sent to a landfill for disposal.



2. Selective Catalytic Reduction with Separated Overfire Air

SCR/SOFA technology is focused on the control of NO_X emissions. SCR is a post-combustion technology that uses catalyst elements, which are housed in a reactor that is installed in the flue gas stream upstream of the air heater. The process utilizes ammonia, which reacts with NO_X in the presence of a catalyst to reduce the NO_X to nitrogen and water.

Ammonia is injected into the flue gas stream well ahead of the catalyst, so the ammonia and NO_X are uniformly distributed as they reach the catalyst. The target temperature window for the flue gas is 625°F ± 25°F to 750°F ± 25°F. Flue gas exiting the SCR reactor will contain low concentrations of unreacted ammonia (called ammonia slip). Slip is limited to 2 ppmvd (parts per million, volumetric, dry) (at 3% O_2) at the SCR outlet. A higher slip value usually indicates that catalyst is beyond its life and is losing effectiveness at reducing NO_X.



The SOFA system is designed to provide optimum mixing of the balance of combustion air with the main combustion zone flue gas during the second stage of combustion within the furnace region of the Plant's cyclone boiler. The unique combustion characteristics of a cyclone furnace allow excellent NO_X reduction to be achieved while maintaining the balance of separated overfire air entry point into the boiler at close proximity to the cyclones themselves.

3. Activated Carbon Injection

ACI technology is focused on the control of mercury emissions. ACI uses powdered-activated carbon ("PAC"), which is pneumatically injected into the flue gas stream prior to the particulate collection equipment, to capture both elemental and ionic mercury ("Hg"). PAC is delivered to the Plant site by truck and pneumatically unloaded into a silo by a blower located on the truck. PAC is blown into the top of the silo and then settles to fill the vessel. Fluidized PAC is then transferred from the silo cone through a rotary airlock feeder into a gravimetric feeder. After the gravimetric feeder, the PAC is blown through a piping system and distributed to an array of injection lances that disperse the PAC into the cross-section of the flue gas ductwork upstream of the particulate control device. In the ductwork, PAC mixes with flue gas and the vapor-phase Hg is adsorbed on the surface of the PAC particle. The PAC particles then are captured in the particulate collection device.

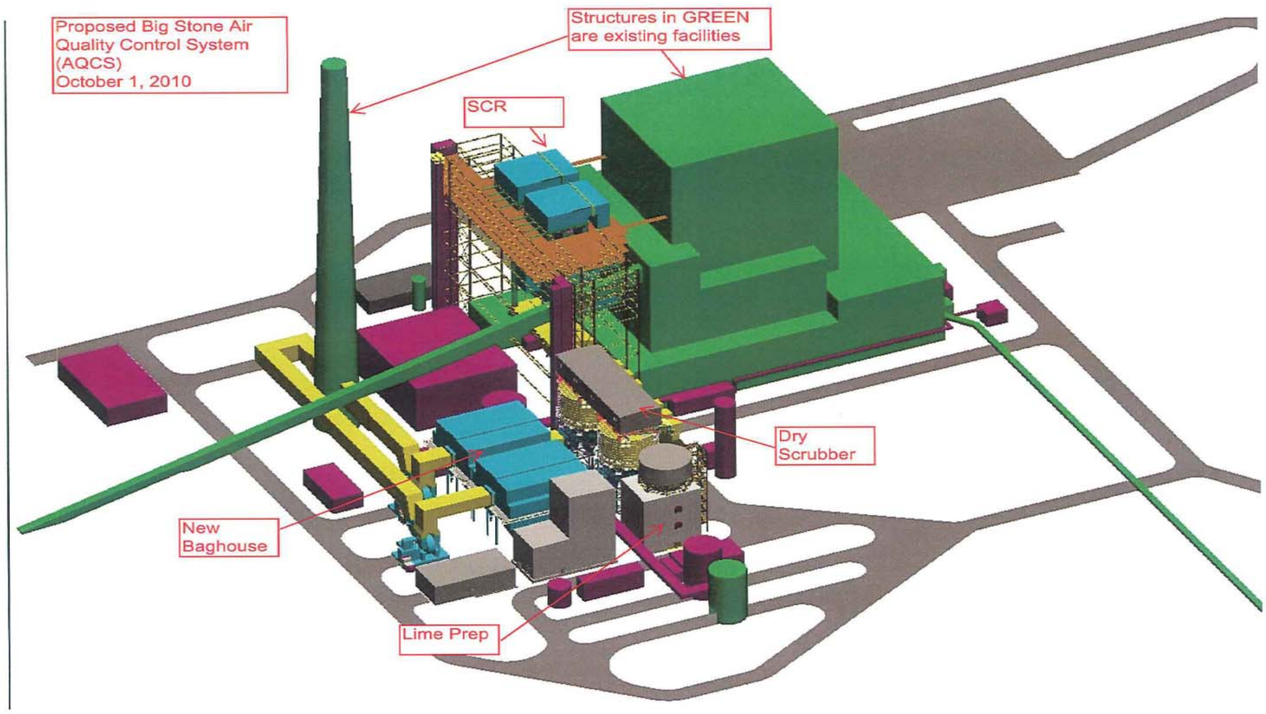
4. Balance of Plant Modifications

In order to install and successfully operate the control technologies that are part of the AQCS Project, the Co-Owners also must make the following balance of plant modifications at Big Stone:

- Modify the boiler to deliver flue gas at the required temperature for operation of the SCR and to maintain or improve boiler efficiency;

- Replace the existing baghouse;
- Replace the ID fans;
- Reinforce the boiler and duct work; and
- Modify the plant electrical infrastructure.

The following schematic depicts the AQCS system as it would be installed at the Plant.



D. Implementation Schedule

The SD Haze SIP and its implementing rules require that the Big Stone AQCS be installed, operated and shown to comply as expeditiously as practicable, but not later than five years from the EPA's approval of the SD Haze SIP.[18] As a result, if the EPA approves the SD Haze SIP in 2011, the Big Stone AQCS may be required to be installed and operational by 2016. To be in compliance by 2016, OTP must finalize the AQCS Project design and start procurement of major elements of the AQCS in early 2012.

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[18] S.D. Admin. R. 74:36:21:07, Installation of Controls based on Visibility Impact Analysis or BART Determination; SD Haze SIP § 6.4, BART Requirements. The SD DENR submitted the SD Haze SIP to EPA on January 21, 2011.

The final deadline for BART compliance will be set by the EPA's approval date. In addition, EPA has the discretion to partially approve a SIP submittal, so there is also the possibility that EPA could decide to approve the Big Stone BART determination in advance of other elements of the SD Haze SIP. This leaves the Co-Owners under the obligation to proceed with the AQCS Project as expeditiously as practicable, and within the timeframe needed to meet a five year compliance deadline that could end by 2016.

The exact compliance deadline is not now known, and is not in the Co-Owners control to determine. The Big Stone AQCS is a large undertaking that will take several years to complete. The main implementation steps, if regulatory approval is received to proceed, include detailed engineering work in 2011, with procurement of major components of the AQCS starting in early 2012. The construction phase will continue into 2015. Once constructed, the AQCS would need to be tied in to the Plant, which would best be done during a scheduled outage of the Plant in 2015. Testing to demonstrate the compliance of the AQCS with the BART emission limits will need to occur within six months of the tie in of the AQCS with the Plant, and in time to start compliant operation before the final compliance deadline.

Attachment 5 to this Application includes a cost estimate and implementation schedule for the Big Stone AQCS Project which provides considerable detail on the steps and time periods involved in completing the project. This implementation schedule shows that the Big Stone AQCS is a five year project, not considering schedule slippage that could occur for a variety of reasons as a complex series of tasks are performed and coordinated over a substantial period of time.[19]

E. Cost Estimate

The estimate of the capital costs to install the AQCS Project at Big Stone, including the semi-dry FGD scrubber, SCR/SOFA, new baghouse and balance of plant changes, escalated to an in-service date of late 2015, is $489,397,400, with an accuracy of +/-20%. Installation of mercury control equipment on the Plant is estimated to cost an additional $5,012,700. The Co-Owners are recommending installation of the mercury control equipment at the time of the AQCS project as the requirement to control mercury emissions is anticipated to become effective within the time frame of the AQCS project. The EPA recently proposed National Emissions Standards for Hazardous Air Pollutants for Coal-Fired Utilities which requires mercury emissions reductions that would apply to the Plant. The rule was proposed on March 16, 2011, and is projected to be final by November 16, 2011. The compliance timeline of the proposed rule requires utilities with coal-fired units to install mercury controls to comply with the rule's established mercury emission limits by early 2015.

The capital cost estimate was prepared for the Plant's Co-Owners by Sargent & Lundy.[20] Sargent & Lundy was selected as the engineering firm for the AQCS Project as part of a request for proposal process that considered cost, experience and expertise. Sargent & Lundy was both

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19 Attachment 5 (Big Stone Plant AQCS Project Cost Estimate).

20 Attachment 5.

the lowest cost firm and the firm that has performed the engineering on more projects like the AQCS Project than any other firm in the country. In particular, Sargent & Lundy has been involved with 57% of the dry FGD projects, 46% of the wet FGD projects and 30% of the SCR projects in the industry.

Sargent & Lundy's detailed explanation of the basis for the capital cost estimate was based on a conceptual design of the project and Sargent & Lundy's experience with similar projects.[21] Because OTP is at the early stages of the engineering process (only 2% of the engineering work has been completed), the estimate includes a contingency range of +/-20%.

The cost estimate has been compared to similar projects that Sargent & Lundy have completed, as adjusted for plant size and year in-service. The results on an equalized basis show that the cost estimate is consistent with other comparable projects. Large retrofit projects such as the AQCS Project at Big Stone typically contain very unique features that result from physical or operating constraints present at the existing plants. These unique conditions often make comparing one project to the other difficult. For example, some plants have considerable space available for new equipment while others are limited in space, and some plants have design margin in their auxiliary power systems, draft systems, etc., while other plants have no or limited available design margin in their existing systems. Consequently, the cost data from projects completed by Sargent & Lundy, as well as, publicly available data from semi-dry FGD and SCR projects completed in the years 2006 to 2010, fall within a fairly wide range of values from \$525/kw_g to \$850/kw_g in 2010\$. Using this cost range as a benchmark, the AQCS Project at Big Stone is consistent with other comparable projects in that the AQCS Project falls near the midpoint of the range of historical costs at a value of approximately \$617/kw_g.[22] In addition to the capital cost, there will be an additional ongoing cost to operate and maintain the AQCS equipment. It is estimated that in 2016, the expected first full year of operation, the additional cost to operate the equipment would be approximately \$11 million (including escalation).[23] The additional operating and maintenance cost would add approximately \$3.50 to the cost to produce a MWh of energy, or \$.0035 per kWh, based on the Plant's net dispatchable energy generation of 3,120,750 MWh. The total annual operating and maintenance costs for the Plant in 2016 with an AQCS will be \$27.3 million,[24] with the share to be borne by Montana-Dakota's North Dakota customers of approximately \$4.0 million and the share borne by OTP's North Dakota customers of approximately \$5.9 million. The biggest operational cost increase (approximately two-thirds

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21 The cost estimate provided in Attachment 5 is a revision to an earlier less detailed cost estimate included in Attachment 4 (SO_2, NO_X, and Mercury Reduction Study) and reflects a substantial reduction in estimated costs for the AQCS Project due to a series of cost optimization decisions about the basic project design. The cost optimizations are summarized in a table describing 14 changes to reduce the estimated capital cost of the AQCS Project from that portrayed in Attachment 4.

22 The cost range and the \$617/kw_g estimate for the Big Stone AQCS Project do not include escalation beyond 2010 and AFUDC. Additionally, the Big Stone AQCS estimate does not include the substantial boiler modifications that are considered to be very unique to the Big Stone AQCS Project.

23 Attachment 6 (Big Stone AQCS Project Operating and Maintenance Cost Calculations).

24 *Id*.

of the operational cost increase) is caused by the lime and ammonia necessary to operate the SCR and semi-dry FGD, as well as the addition of employees at the Plant.[25]

The addition of control for mercury, which is likely to occur in the same timeframe, would add an operating and maintenance cost of approximately $2 million per year.[26] This would add approximately $0.65 to the cost to produce a MWh of energy, or $.00065per kWh.

F. Efforts to Insure Lowest Reasonable Costs

To ensure the lowest reasonable cost, the Co-Owners will: (1) use a request for proposal to select the lowest evaluated cost; (2) use a single erection contractor to manage installation to insure coordinated site work; (3) use separate requests for proposal for each major portion of the AQCS Project to allow for competition in the bidding process; and (4) aggressively manage the project to assure lowest reasonable cost.[27]

OTP on behalf of the Co-Owners, requested recommendations from Sargent & Lundy on how to manage the contracting process for the AQCS Project to insure that the project is implemented at lowest reasonable cost. Sargent & Lundy has a record of engineering and delivering AQCS projects at a lower cost than its competitors, and has worked on over half of the projects in the country that are similar to the AQCS Project. The analysis Sargent & Lundy provided is included as Attachment 7 to this Application.

Sargent & Lundy recommended an approach to managing the AQCS Project that will attempt to take advantage of favorable market conditions, but which will ensure the lowest reasonable cost if market conditions become more adverse as the AQCS Project is implemented. Under the recommended approach, the Co-Owners plan to solicit bids from suppliers for each major portion of the AQCS pollution control systems (the semi-Dry FGD, the SCR and the balance of plant modifications). This approach will allow the Co-Owners to go to the market sooner than is possible if the entire project must be developed as part of an Engineer Procure Construct solicitation. In addition, the Co-Owners plan to contract with a single erection contractor, to minimize the problems that can occur from multiple interfaces between numerous contractors. This approach will improve scheduling, resulting in better utilization of resources that will assist in achieving the lowest reasonable cost for the AQCS Project.

The Co-Owner's approach will avoid the potentially adverse costs of a date certain/price certain turnkey project, which could cost +/-10% or more (+/- $50 million). A turnkey approach, in addition to being too costly, would constrain the Co-Owners' ability to use the advantage to schedule early in the project through the procurement of equipment under current favorable market conditions, restrict the ability to select individual contractor combinations, disqualify potentially more cost-effective regional contractors who would not have the ability to bid on the

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[25] Attachment 6; Attachment 4, Section 6.

[26] Attachment 6.

[27] If market conditions change greatly, this could result in changes in the contracting approach currently contemplated for the project.

project as a whole, restrict the Co-Owners' input during design development, and increase contingencies because the contractor's bid is based on less-developed engineering. Similarly, a contract approach using multiple suppliers and contractors managed by the Co-Owners has risks due to the complexity of interfaces between too many entities.

The Co-Owners' proposal strikes the proper balance by breaking the project into its fundamental building blocks: the different suppliers of pollution control systems and the erection work. Issuing requests for bids with more developed designs minimizes costs by reducing the contingencies that bidders would otherwise need to work into their proposed prices. The Co-Owners believe that this approach is the best approach to ensure that the AQCS Project is implemented at the lowest reasonable cost.

To keep interested parties and the Commission apprised of the implementation and costs of the AQCS Project, OTP and Montana-Dakota propose to set up a quarterly reporting mechanism with the Commission that would identify if there are any changed circumstances that will materially affect the cost of the AQCS Project.

G. Alternatives to Big Stone AQCS Project

The Co-Owners are proposing to undertake the Big Stone AQCS Project in order to comply with the SD Haze SIP and its associated implementing rules in order to continue operating a Plant representing a significant baseload resource for each utility. The SD Haze SIP specifies the control technology that represents BART for the Big Stone Plant and establishes emission limitations to reflect installation of the BART technology. The emission limitations reflect the emissions expected from installation and proper operation of an AQCS at the Big Stone Plant consisting of a semi-dry FGD, SCR/SOFA and baghouse. Because the BART requirement is a direct requirement that has been individually determined for Big Stone, the only alternative to installing the AQCS and achieving regulatory compliance is to cease operations at the facility. The Co-Owners have considered alternatives to the AQCS Project, including the costs and benefits of retirement or repowering of the Plant with natural gas. The analysis of alternative response scenarios is provided in Joint Exhibit 2.

II. Joint Exhibit 2 - REASONABLENESS OF BIG STONE AQCS PROJECT

The South Dakota DENR is the state agency responsible for implementing federal CAA requirements to reduce emissions that may contribute to regional haze from emitting facilities located in South Dakota, including the Big Stone Plant. After conducting a thorough analysis of pollution control options, the DENR determined that the control technologies in the AQCS Project must be required. As a result, the Big Stone Plant Co-Owners must design, construct, install and operate the AQCS by the compliance deadline established by the DENR, or the Plant will not be able to continue operation.

OTP, on behalf of the Co-Owners, has prepared an assessment of alternative scenarios that may be available to respond to the anticipated environmental regulations.[28] OTP developed four response scenarios and evaluated the comparative costs under each scenario using a 20-year levelized cost analysis:

1. Implementing the Big Stone AQCS Project, as Co-Owners have proposed;
2. Repowering Big Stone boiler with natural gas;
3. Retiring/Replacing Big Stone with a CCGT Plant; and
4. Retiring/Replacing Big Stone with a CCGT Plant and purchased wind power.

As shown in Table 2, the AQCS Project is the most economical scenario under all analyses in the Base Case.[29] The analysis of these alternative scenarios was carried out for a Base Case, which also considered the anticipated environmental costs for mercury control and coal ash disposal, as well as the cost of the stranded asset if one of the retirement/replacement options were to be implemented. Table 2 below presents a comparison of the alternative scenarios under the Base Case analysis, including an analysis that incorporates the cost to cover the stranded asset costs ("Stranded Asset Cost Scenario"), and an analysis that includes an additional $5 million in capital cost and $2 million in annual O & M cost for mercury removal and $6.66 million in annual O & M cost for handling coal ash if it is characterized as a hazardous waste ("High Environmental Cost Scenario").

Table 2 – Estimated Levelized Energy Cost (2016$/MWh)

	Big Stone + AQCS	CCGT + Wind	CCGT	Big Stone with Natural Gas
Combined Levelized Energy Cost - (Base Case)	$74.38	$100.43	$103.38	$117.25
Total Energy Cost Including	$74.38	$104.24	$107.19	$117.25

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[28] Response scenarios that would not be available in the required timeframe, or could not replace the characteristics that Big Stone provides were not further analyzed. The selection of response scenarios that may be viable is fully explained in Joint Exhibit 3.

[29] Attachment 9 (Big Stone Pro Forma Economic Analysis) at 5-6.

Stranded Asset Cost				
Total Energy Cost Including High Environmental Costs	$78.04	$100.43	$103.38	$117.25

The Base Case analysis comparing installation of the AQCS with various options for repowering or retiring and replacing the Plant with natural gas shows that the AQCS is the most cost-effective option, with the cost of the other options at least $26 per MWh or 35% higher than the levelized MWh cost of the proposed AQCS.[30] The AQCS remains the most cost-effective option under several sensitivity analyses concerning capital cost (+/-30%), fuel cost (+/-20%), and O & M cost (+/-20%).

30 Attachment 9 at 6.

III. Joint Exhibit 3 - ASSESSMENT OF FINANCIAL AND OPERATIONAL IMPACTS OF PENDING ENVIRONMENTAL REGULATIONS TO THE BIG STONE PLANT

The Co-Owners provide this assessment of the financial and operational impacts of pending environmental regulations, including the SD Haze SIP, to the Big Stone Plant. The assessment covers the installation of the pollution controls that comprise the proposed AQCS, as well as other regulatory response scenarios that may be reasonable in view of the costs to comply with the SD Haze SIP, including the retirement or repowering of the Big Stone Plant with natural gas.

By installing the AQCS, the Co-Owners customers will continue to receive the benefits of low-cost, reliable electric power from an existing baseload resource, without the need for development of either a greenfield site or new transmission. In addition, as a baseload resource that is frequently used for load following, the Big Stone Plant is a critical resource for a system that is becoming more dependent on wind power and other variable resources. As this Assessment shows, the continued operation of the Big Stone Plant with the addition of the AQCS is a cost effective means to the meet the future needs of the Co-Owners' customers when taking into the account the costs required to comply with the SD Haze SIP and other pending environmental regulations and other viable regulatory response scenarios. The cost estimates and analysis provided in this Assessment were prepared by OTP, on behalf of the Co-Owners with assistance from the engineering firms of Sargent & Lundy and Burns & McDonnell.

A. FINANCIAL AND OPERATIONAL IMPACTS OF PROPOSED AQCS PROJECT

The SD Haze SIP determined that BART for the Plant is comprised of a separated over fired air system for the Big Stone Plant boiler to reduce the formation of NO_X , an SCR to chemically reduce NO_X into N_2 and H_2O, a Semi-Dry FGD for SO_2 control, and a baghouse for particulate matter control. The AQCS Project would also include all the ductwork, boiler modifications and infrastructure changes needed to support the required equipment. The AQCS Project is necessary to meet the BART requirements of the SD Haze SIP and its implementing regulations. Without installation of the AQCS, the Plant will not be able to comply with the emission limitations that represent BART, and cannot operate after the deadline for BART compliance has passed.[31]

1. Financial Impacts of Proposed AQCS Project

The estimated capital cost for acquisition and installation of the equipment and support systems for the AQCS is approximately $489 million (2015 dollars).[32] This estimate provides an accuracy range of +/- 20% and is the total project cost escalated to its commercial operation date, which is expected to be late in 2015. Montana-Dakota's North Dakota customers will see an approximate 16 percent increase in rates as a result of its share of this total project cost of $78

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31 *See* ADP Application, Joint Exhibit 1, Section B, Requirement to Implement the Big Stone AQCS Project.

32 *See* Attachment 5 & ADP Application, Joint Exhibit 1, Section E, Cost Estimate.

million. OTP's North Dakota customers will also see an approximate 16 percent increase in rates as a result of its share of this total project cost of $108 million.

The estimated additional increase in the Plant's operation cost in 2016, the expected first full year of operation, associated with the operation of the AQCS, will be approximately $11 million (including escalation from 2010 dollars).[33] The additional operating expense will increase the cost to produce a MWh of energy by approximately $3.50, or $.0035 per kWh, based on the Plant's net dispatchable energy generation of 3,120,750 MWh. After the AQCS is installed and in operation, the estimated total operating cost for the Plant in 2016 is $27.3 million,[34] with Montana-Dakota's North Dakota share being approximately $4.0 million and OTP's share of approximately $6.0 million. The biggest operational cost increase will be due to the cost of the lime and ammonia necessary to operate the SCR and semi-dry FGD and the addition of employees at the Plant.[35]

Beyond the additional cost to install and operate the AQCS, additional capital and operating costs are likely to be required in response to anticipated regulations for control of mercury emissions and disposal of coal combustion residual (coal ash).[36] The addition of control for mercury, which is likely to be required during the same timeframe as the AQCS Project, is estimated to result in additional capital cost of approximately $5 million[37] and an additional operating cost of approximately $2 million per year.[38] The estimated cost to comply with regulations relating to mercury control will add approximately $0.65 to the cost to produce a MWh of energy, or $.00065 per kWh.

Table 1 contains a summary of the potential anticipated financial impacts of the proposed AQCS, mercury emission standard, and the potential cost of coal ash regulation.

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[33] Attachment 6.

[34] Attachment 6.

[35] Attachment 4, Section 6.

[36]. In addition to the requirements for the AQCS, the Assessment of Financial and Operational Impacts of Pending Environmental Regulations to the Big Stone Plant considered potential cost of new environmental regulations applicable to the Big Stone Plant relating to mercury emission limits and coal ash disposal.

[37] Attachment 5, ACI Estimate.

[38] Attachment 6.

Table 1 – Anticipated Financial Impacts

	Capital Cost (2015$)	Annual O & M Cost (2016$)	Levelized Cost (2016$/MWh)
Big Stone + AQCS	$489 million[39]	$27.3 million[40]	$74.38[41]
Mercury Control and Coal Ash Disposal[42]	$5 million	$8.7 million	$3.66[43]

2. Operational Impacts of Proposed AQCS Project

Apart from capital and increased operating costs, the installation of the AQCS will not have any significant impacts on the capacity or day-to-day operations of the Big Stone Plant, except for one longer than typical outage in 2015 to connect the AQCS into the Plant once the AQCS systems have been constructed. However, there are certain challenges that are being addressed in the design of the proposed AQCS Project and that have been included in the cost estimates for the AQCS.

First, some modifications need to be made to the boiler to allow for effective operation of the SCR. The SCR provides effective control of NO_X emissions, but it operates well only within a specified temperature range.[44] The boiler temperatures must be maintained so they are neither too hot at full load nor too cold at low loads. To ensure that proper temperatures are maintained, the Plant's boiler will need to be modified.[45] The boiler efficiency is expected to improve as a result of the modifications, and the hourly boiler heat input will not increase above the current permitted levels.

The design of the AQCS equipment must also allow the Plant to maintain its current ability to follow load. Varying load conditions must be taken into account in the design of the semi-dry FGD and SCR. Currently, the Plant will run in a load following arrangement for much of the

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39 Attachment 5.

40 Attachment 6.

41 Attachment 9 at 6, Table 2.

42 The addition of mercury control equipment is estimated to cost approximately $5 million, Attachment 5, ACI Estimate, and the annual O & M cost for the mercury control equipment is estimated to be $2 million, Attachment 6. The increased costs for disposal of coal ash could be as high as approximately $6.7 million per year, based on a $37.50 per ton estimate for disposal, including both capital and operating costs. Section IV; *Special Reliability Assessment: Resource Adequacy Impact of Potential U.S. Environmental Regulations*, at 57, NERC (October 2010).

43 Attachment 9 at 5-6.

44 Attachment 4 at 3-4.

45 Attachment 4, Section 3.2, describes boiler modifications that are anticipated to be needed as a result of the AQCS Project.

spring and fall. For example, on a typical spring day when the demand for electricity is relatively low, the Plant is likely to see minimum load at night, but as the electrical load starts increasing, the output of the Plant will rise until it reaches full load during the peak load periods, and then drop off as the electric load drops off at night, eventually getting back to the minimum load for a few hours before repeating the cycle. The design of the AQCS equipment will assure that the ability of the Plant to follow load is not compromised and that the AQCS Project does not decrease the range of load at which the unit may efficiently and safely operate. For example, the AQCS Project will be designed to minimize the duct distance between the semi-dry FGD and the baghouse to limit the amount of ash depositing in the duct work at low loads. Other design considerations involve ensuring that proper temperatures are maintained and that equipment is the appropriate size to operate at both low and full loads.[46]

Other operational impacts of the AQCS Project will include the addition of employees to operate and maintain the Plant with the additional equipment.[47] OTP will provide training on operation of the new equipment to the new employees. Additionally, operation of Big Stone following installation of the AQCS will produce a greater volume of ash to be disposed of because the addition of the semi-dry FGD will result in ash that is less dense than the ash currently produced by the Plant. OTP has sufficient capacity in its existing disposal site for this ash.[48]

B. ALTERNATIVE RESPONSE SCENARIOS

1. Selection of Alternative Response Scenarios

OTP, on behalf of the Co-Owners has focused on the identification of alternative scenarios that involve either the retirement and replacement or the repowering of the Big Stone Plant. In view of the specific requirements set out in the SD Haze SIP and its implementing regulations, there is only one response scenario that involves the installation of pollution control equipment and that scenario is the proposed AQCS Project. In addition, the use of pollution allowances is not a viable compliance approach because there are no pollution trading programs available that can substitute for BART compliance and address the underlying regulatory concern for visibility in Class I areas.[49]

OTP, on behalf of the Co-Owners, assessed the current status of Greenhouse Gas Regulatory requirements when considering alternatives. Congress has considered, but has not adopted, legislation which would require a reduction in Greenhouse Gas (GHG) emissions. However,

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46 Attachment 4 at 2-5.

47 Attachment 4 at 6-1.

48 *Id.* at 3-22.

49 Emission trading of SO_2 and NO_x may have limited potential to be an option for plants located in the Transport Rule's control zone, subject to affected state decisions in their regional haze SIPs, but South Dakota is not a state proposed for inclusion under that rule. Emission trading of SO_2 under the Acid Deposition Program is in addition to, and does not affect the requirement to comply with other CAA program requirements, such as the regional haze program. 42 U.S.C. § 7651b(f) (CAA § 403(f)).

there is no legislation under active consideration at this time. The EPA is proceeding to regulate GHGs under a number of provisions of the Clean Air Act beginning with regulation under the Prevention of Significant Deterioration (PSD) and the Title V permitting process in January 2011. OTP does not anticipate making modifications at Big Stone as part of the AQCS project that would trigger PSD requirements, including for GHGs. Consequently, GHG emissions are not projected to trigger the need for a PSD permit as a result of the AQCS Project.

EPA has announced a timeframe for developing New Source Performance Standards (NSPS) for GHGs from electric generating units. EPA plans to propose this NSPS in August 2011, and adopt the standard in June 2012. In general, NSPS become applicable to new sources built after the effective date of the regulation, or affect what may be required to be included as an emission control at the time an existing source makes a change significant enough to trigger NSPS applicability. To trigger the applicability of NSPS, an existing source must make a modification that increases its maximum hourly emissions rate. The Co-Owners do not anticipate making a modification at Big Stone Plant that would trigger NSPS requirements. The Big Stone AQCS Project is not projected to trigger the applicability of the NSPS for GHGs that EPA plans to develop.

At the same time EPA develops the NSPS, EPA also plans to issue emission guidelines for existing sources under CAA Section 111(d) (111(d) Standard). A 111(d) Standard, unlike the NSPS, applies to an existing source. States are given a period of time to develop plans to implement a 111(d) Standard, and if a state does not develop such a plan, EPA will prescribe a plan for that state.

While the potential impact of a 111(d) standard on Big Stone is not yet known, standards of performance for GHGs, especially for existing sources, are anticipated to focus on efficiency improvements rather than add-on controls. The Co-Owners have in the past implemented efficiency measures at Big Stone through installation of a more efficient steam turbine at the Plant. The capital cost of efficiency improvements could be offset in whole or in part by reduced fuel costs.

To identify potentially viable alternatives for economic evaluation, OTP, on behalf of the Co-Owners first identified the needs currently served by the Big Stone Plant, as well as the basic operating characteristics of the Plant. The Big Stone Plant is a key baseload asset for its three utility Co-Owners, serving the existing load of customers in several states. The Plant is the largest baseload resource for each of the Co-Owners. Given the critical resource role played by the Big Stone Plant, OTP, on behalf of the Co-Owners developed alternatives that were capable of reliably: (1) producing approximately 3 million megawatt-hours of electricity per year; (2) serving as a baseload resource, with the ability to follow load and be a dispatchable resource with high availability; and (3) being in operation prior to expiration of the deadline for Big Stone to comply with the BART requirement. Analysis performed by the Midwest Independent Transmission System Operator ("MISO") has assumed the presence of a baseload generation source at the Big Stone site, and any change in location would require a reevaluation of the transmission system.

Given the significant customer load served by the Big Stone Plant, the Co-Owners identified coal, hydropower, nuclear and natural gas as practical potential replacement options that could

meet the above criteria.[50] Since the proposed AQCS Project includes continuation of coal generation at the Plant, another coal option was not considered as an alternative response scenario. Hydropower and new nuclear generation were rejected because expected permitting difficulties suggest that these resources could not be available in the timeframe required for compliance with the SD Haze SIP and its implementing rules and because the size of these alternatives to be economic, would exceed the needs of the Co-Owners. Based on these considerations, it was determined that natural gas was the only viable retirement/replacement or repowering option that could potentially replace the current functions of the Big Stone Plant in the required timeframe.

With respect to natural gas, three different scenarios were assessed:

1) Converting the existing Big Stone boiler to natural gas combustion;
2) Constructing a new gas-fired combined-cycle turbine at the Big Stone site, abandoning the existing equipment at the Plant; and
3) Combining a new gas combined-cycle turbine at the Big Stone site with wind generation.

Due to the timing of the compliance requirement for operation of the AQCS under the SD Haze SIP, it is unlikely that any of these three natural gas scenarios could be engineered, designed, permitted, procured, and constructed in the same timeframe as the Big Stone AQCS Project. Consequently, there would like be a minimum period of one to three additional years between the retirement of the current Big Stone Plant and the availability of these new resources, during which time OTP, NorthWestern Energy and Montana-Dakota would be dependent on the market or contracted purchases to meet the needs of their customers for the three million MWh per year currently provided by Big Stone. Assessment of the natural gas scenarios are provided below.

Other repowering scenarios were considered and ultimately rejected as infeasible, including one scenario involving repowering the existing generating unit with biomass. Biomass fuel may be capable of co-firing up to 10% of the heat input of the Plant, but this would not remove the AQCS Project requirement if coal still comprised 90% of the fuel mix. Achieving a 10% level of biomass as fuel would require drawing on most of the available biomass in a 30 to 50-mile radius, with an estimated delivered cost of \$8 to \$9 per million Btus. This is approximately four times higher than the cost of coal and approximately twice that of natural gas. The conversion to biomass fuel is not a viable response scenario because the AQCS Project would still be required, as well as the cost and logistical challenges involved in securing sufficient biomass fuel.[51]

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50 Conservation and load management were not considered as a feasible alternative response scenario to replace this significant existing baseload facility, as conservation and load management are already assumed to be necessary to meet future resource needs.

51 The most readily available source of biomass in the area is corn stover. This fuel would likely be delivered in large round bales with 20 to 25 bales per semi-load. At the current firing rate, the Big Stone Plant would need to consume close to ten of these large bales every minute due to the low Btu value, high moisture and low density of the fuel. Thus, biomass co-firing is not a viable regulatory response scenario.

The Co-Owners also rejected as infeasible a scenario involving the construction of a gas-fired combustion turbine and a heat-recovery boiler at the Big Stone site, and the use of that steam generation to power the existing Plant turbine. To implement this type of conversion, approximately two-thirds of the generation would come from the new gas-fired generation and one-third would come from the existing steam turbine. The existing steam turbine at Big Stone produces 475 megawatts. Using the 1/3 to 2/3 ratio, the generation from the Big Stone Plant would be required to increase from 475 megawatts to 1,425 megawatts. This additional generation would overload available transmission, since there are already over 2,000 megawatts in the queue at the Big Stone site for additional transmission, and thus could not be available before the AQCS Project's compliance deadline. In addition, this scenario would generate roughly 1,000 megawatts of additional intermediate load generation that is unlikely to fit the needs of the current Big Stone Co-Owners. Due to the time delay, the mismatch of resources and the high cost for such a sizeable gas plant, this response scenario was not further evaluated.

2. Comparative Analysis of the Financial Impacts of Proposed AQCS Project and Alternative Regulatory Response Scenarios

To assess financial impacts, the Co-Owners retained the engineering firm of Burns & McDonnell to perform a pro forma economic analysis to calculate the levelized costs of power for the AQCS Project and the alternative response scenarios.[52]

To simplify the analysis, Burns & McDonnell assumed that all response scenarios would be available by January 1, 2016. This assumption favors the alternative scenarios because the Burns & McDonnell analysis does not include any allowance to cover the need to purchase energy from the market during the period, very likely to run at least one to three years (2016 to 2018), between the retirement of Big Stone and the commercial operation of the natural gas scenarios.[53]

To perform its analysis, Burns & McDonnell, as much as possible, used the same modeling inputs as provided by OTP in its most recently filed Minnesota Integrated Resource Plan ("IRP") in Minnesota Docket No. E017/RP-10-623. Courtesy copies were filed with the North Dakota Public Service Commission in late June of 2010. When the necessary inputs for this ADP analysis were not available in the IRP filing, Burns & McDonnell's assumptions were based upon either the analyses prepared by Sargent & Lundy for OTP or the recent project experience of Burns & McDonnell, including its work on projects involving more than 25 gigawatts of gas-fired generation in the last ten years.[54] Montana-Dakota reviewed the assumptions provided by OTP and agrees that the Burns & McDonnell analyses reasonably represent alternatives available to Montana-Dakota.

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52 The Burns & McDonnell analysis is provided in Attachment 9.

53 OTP has estimated that the likely cost to enter into a Power Purchase Agreement ("PPA") to meet customer needs during the lag period would be between $87 million and $262 million. This estimate assumed the lowest cost option would be a coal PPA.

54 The Sargent & Lundy analyses are provided in Attachments 5, 6, and 8.

Burns & McDonnell's analysis covers a 20-year period of operation (which provides a reasonable time period for cost recovery and is within the useful life of the equipment being added and the existing plant) and levelizes construction and operation (including fuel) costs into a levelized cost per Megawatt Hour (MWh). In addition to considering a Base Case analysis, Burns & McDonnell also calculated energy costs if stranded asset costs were included in the repowering and retirement/replacement scenarios and if additional costs for environmental controls for mercury and coal ash were included in the AQCS scenario.

a. Base Case Analysis

As provided in Joint Exhibit 2, Burns & McDonnell analysis found the AQCS Project the most economical scenario by a substantial margin.[55] Under the Base Case scenario, the AQCS Project is the lowest cost option by 35% over the next lowest cost option, the combined cycle plus wind. Adding the stranded asset cost to the combined cycle plus wind option increases this differential in the cost of energy between these two options to 40%, while adding the high environmental costs to the AQCS reduces the cost differential to 29%.[56]

Table 2 below (also presented in Joint Exhibit 2) provides the results of the Burns & McDonnell analysis. The estimated cost for each scenario in the Base Case analysis is provided in the horizontal row identified as "Combined Levelized Energy Cost." The estimated levelized energy costs if stranded asset costs are included for the repowering and retirement/replacement scenarios is provided in the horizontal row "Stranded Asset Cost Scenario." And, the estimated levelized energy costs if additional costs for environmental controls for mercury and coal ash disposal are included in the AQCS option is provided in the row marked as "High Environmental Cost Scenario."[57]

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55 Attachment 9 at 6-12.

56 Attachment 9 at 6-7.

57 Under the High Environmental Cost Scenario, Burns & McDonnell assumed an additional $5 million in capital cost and $2 million in O & M cost for mercury emission control and an additional $6.66 million for handling coal ash if it is characterized as a special waste under the RCRA hazardous waste rules. Attachment 9 at 6.

Table 2 – Estimated Levelized Energy Cost (2016$/MWh)[58]

	Big Stone + AQCS	CCGT + Wind	CCGT	Big Stone with Natural Gas
Combined Levelized Energy Cost – (Base Case)	$74.38	$100.43	$103.38	$117.25
Total Energy Cost Including Stranded Asset Cost	$74.38	$104.24	$107.19	$117.25
Total Energy Cost Including High Environmental Costs	$78.04	$100.43	$103.38	$117.25

b. Sensitivity Analyses

In addition to the Base Case analysis, Burns & McDonnell prepared three sensitivity analyses to assess the effects of capital cost variations, fuel cost variations and operational cost variations.

(1) Capital Cost Sensitivity Analysis

In this analysis, Burns & McDonnell ran a sensitivity case to consider the effect of a range of capital costs (plus or minus 30%). In all cases, the AQCS Project was the low cost scenario and by a substantial margin. For the low end of the range for capital costs (minus 30%), levelized costs of energy for the AQCS Project were estimated to be $66.24 MWh compared to $90.09 MWh for the next least cost scenario (combined cycle and wind). For the high end of the range for capital costs (plus 30%), the levelized energy cost for the AQCS Project was $82.51 MWh compared to $106.63 MWh for the next lowest cost option (combined cycle wind).[59]

(2) Fuel Cost Sensitivity Analysis

In this analysis, Burns & McDonnell ran a sensitivity analysis to determine the impact of changes to the fuel costs for each option. The analysis considered the effect of a range of fuel costs (plus or minus 20%). Over the range of fuel costs evaluated, the AQCS Project was preferred in all instances. For the low end of the range of fuel costs (minus 20%), levelized costs of energy for the AQCS Project were estimated to be $66.24 MWh compared to $90.09 MWh for the next least cost scenario (combined cycle). For the high end of the range for capital costs (plus 20%), the levelized energy cost for the AQCS Project was $82.51 MWh compared to $106.63 MWh for the next lowest cost option (combined cycle wind).[60]

(3) O & M Sensitivity Analysis

A sensitivity analysis was performed to determine the impact of changes in O & M costs (plus or minus 20%). The AQCS Project was the preferred option over the range of costs evaluated. In

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[58] Attachment 9 at 6, Table 2.

[59] Attachment 9 at 8, Figure 1.

[60] Attachment 9 at 9, Figure 2.

all cases, the AQCS Project was the low cost scenario and by a substantial margin. For the low end of the range for O & M costs (minus 20%), levelized costs of energy for the AQCS Project were estimated to be $72.21 MWh compared to $99.47 MWh for the next least cost scenario (combined cycle and wind). For the high end of the range for capital costs (plus 20%), the levelized energy cost for the AQCS Project was $76.54 MWh compared to $101.38 MWh for the next lowest cost option (combined cycle wind).[61]

3. Comparative Analysis of the Operational Impacts of Proposed AQCS Project and Alternative Regulatory Response Scenarios

The financial analysis makes a comparison between the Big Stone AQCS Project and other regulatory response scenarios based on having response scenarios fully capable of replacing the capacity, energy output and dispatchable qualities provided by the Big Stone Plant. There are, however, additional operational differences that are likely to occur between the Big Stone AQCS and implementation of any of the natural gas-based regulatory response scenarios.

a. Operational Issues for All Natural Gas Response Scenarios

All three natural gas scenarios will impose significantly higher costs per MWh of electricity produced than would the AQCS Project. This in turn means that while the natural gas response scenarios are *capable* of replacing the Big Stone Plant's capacity and energy output, they are likely to be run at significantly lower capacity factors, requiring more frequent access to the market for energy purchases. As a result, significant amounts of power would be purchased at prices lower than the natural gas scenarios, but considerably higher than the energy cost of Big Stone after installation of the AQCS.

For example, an energy purchase of $95/MWh in the Base Case analysis would be economical compared to the natural gas scenarios, but would be $22/MWh more expensive than power that could be produced by Big Stone with the AQCS Project. To the extent that market price at any given time does not support the operation of natural gas plants, this power is likely to be produced through other means, including by coal-fired power plants.[62] And in situations where less power is available on the market, the natural gas scenarios would need to be employed, at substantial additional cost to the utilities' customers.

The market price/operating cost dynamics that will lower the capacity factors for the natural gas response scenarios also reduce their usefulness for load following wind resources. A high capacity factor baseload resource such as the current Big Stone Plant (and the Big Stone Plant with AQCS) is running many more hours of the year (for example, 85% of the time compared to

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61 Attachment 9 at 10, Figure 3.

62 The AQCS Project will significantly reduce SO_2 and NO_x emissions from the Plant, while maintaining current high control of particulate matter. In addition, mercury control is planned to target a 90% emission reduction, implemented at the same time as the AQCS. In general, the natural gas options are expected to require installation of NO_x control, but have little emissions of the other pollutants. The extent to which natural gas scenarios would result in less emissions of these pollutants would depend on what the source is for power purchased on the market to fill in for the expected lower capacity factor of the natural gas scenarios.

50% or less of the time), allowing its power output to be increased and decreased quickly in a load following function without the need for a full start up or shut down of the unit.

Deploying any of the natural gas scenarios thus includes dramatically increasing the exposure of the utilities' customers to the market price of power and to fluctuations in the price of natural gas, while reducing the load following capability of the Plant. The next sections assess operational impacts that are individual to each regulatory response scenario.

b. Repowering the Big Stone Plant with Natural Gas

Repowering the Big Stone Plant's boiler to burn natural gas is the highest cost option in the Base Case and among the various sensitivity analyses. Repowering would be less efficient than a new CCGT, which is illustrated by the substantially higher fuel cost in the Base Case ($99.70/MWh), compared with the other natural gas response scenarios ($66.44/MWh). The high operating cost of the repowered unit would likely result in limited use of the Plant.[63] As a result, the repowering scenario would expose customers to both additional market purchases and more expensive market purchases than the other natural gas scenarios.

A repowered unit would take approximately two days to start up and shut down, considerably longer than a new CCGT. High market prices would therefore need to be predicted for a long period of time to justify start up of a repowered unit. In addition, this start up time, combined with a limited use profile, would make a repowered unit unable to effectively load follow wind energy resources on the utilities' electric systems.

c. Retirement and Replacement with Natural Gas Combined Cycle Plant

Replacement of the Big Stone Plant with a new natural gas combined cycle unit at the Big Stone site was evaluated in two scenarios: CCGT and CCGT/Wind Power Purchases. Both scenarios are significantly higher cost in the Base Case, as well as in all sensitivity analyses.

Operationally, the CCGT scenario would allow a faster start up and shut down time than the repowering scenario. CCGTs would start up or shut down in 3-5 hours, substantially slower than a peaking unit such as a Simple Cycle Gas Turbine, which can start up in 10 minutes.[64] Due to its cost of power per MWh, however, a CCGT would likely have an intermediate, rather than a baseload, capacity factor of about 30 to 50%. This would make it less desirable for load following because it would have many more hours during the year when it is not operating at all. Load following would therefore require more start ups and shut downs than for a baseload plant, increasing the O & M costs for the unit. When a CCGT unit is running, however, it would be capable of increasing or decreasing its output to follow load.

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63 The repowered unit would be expected to have the highest cost per MWh, despite its relatively lower capital cost ($267 million) than the other natural gas response scenarios ($621.29 million), because its lower efficiency increases its fuel cost per MWh of power produced. *See* Attachment 9 at 6, Table 2.

64 A Simple Cycle Gas Turbine ("SCGT") is not a viable alternative response scenario, because it cannot replace the Big Stone Plant as a baseload resource.

The CCGT and CCGT/Wind Power Purchases scenarios have similar costs per MWh through the different sensitivity analyses, with the CCGT slightly more expensive except in the case of a drop in the price of natural gas of 10% or more. The capital cost of the CCGT scenarios, $621,289,115 (2016$), is about 27% higher than the capital cost of the Big Stone AQCS Project.

C. CONCLUSION

The financial analysis demonstrates that the Big Stone AQCS is the most economic scenario in the Base Case, and in the Base Case with an increase for Stranded Asset Costs and for anticipated environmental costs ("High Environmental Cost"). The Base Case analysis comparing installation of the AQCS with various options for repowering or retiring and replacing the Plant with natural gas shows that the AQCS is the most cost-effective option, with the cost of the other options 35% or more higher than the levelized MWh cost of the proposed AQCS. The AQCS remains the most cost-effective option under several sensitivity analyses concerning capital cost (+/-30%), fuel cost (+/-20%) and O & M cost (+/-20%).

Under multiple scenarios that consider potential changes in capital, O & M and fuel costs, the Big Stone AQCS remains the least cost option. This conclusion does not change when considering the potential for additional costs that may be imposed by anticipated environmental regulation. Repowering is the highest cost natural gas scenario, with the worst load following capability. Retirement of the Plant and replacement with a CCGT has a significantly higher capital cost than the Big Stone AQCS.

Implementation of any of the natural gas response scenarios instead of the Big Stone AQCS would unreasonably expose North Dakota customers to significantly higher costs under a wide range of potential future conditions. In addition, deploying any of the natural gas scenarios dramatically increases the exposure of North Dakota customers to the market price of power and to fluctuations in the price of natural gas, while reducing the load following capability of the Plant.

The assessment of the financial and operational inputs of the anticipated regulations to the Big Stone Plant demonstrates that the proposed AQCS Project is reasonable and prudent.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF NORTH DAKOTA

IN THE MATTER OF OTTER TAIL POWER COMPANY'S APPLICATION FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR ITS BIG STONE AIR QUALITY CONTROL SYSTEM PROJECT	)))))))	**CASE NO. PU-11-____**

VERIFICATION

STATE OF MINNESOTA)
) ss.
COUNTY OF OTTER TAIL)

MARK ROLFES, being first duly sworn on oath, deposes and says that he is the Manager of Generation Development for Otter Tail Power Company, operating agent for the Big Stone Generating Station; that: Joint Exhibit 1 - The Big Stone Air Quality Control System Project, Joint Exhibit 2 - Reasonableness of Big Stone AQCS Project, and Joint Exhibit 3 - Assessment of Financial and Operational Impacts of Pending Environmental Regulations to the Big Stone Plant, were prepared under his direction; that he knows and verifies the contents thereof, and that the same are true and correct to the best of his knowledge and belief.

Dated this 18th day of May 2011.

/s/ MARK ROLFES
MARK ROLFES

Subscribed and sworn to before
me this 18th day of May, 2011.

/s/ WENDI A. OLSON
Notary Public
My Commission Expires: 1-31-2015

ATTACHMENT 1

SOUTH DAKOTA REGIONAL HAZE STATE IMPLEMENTATION PLAN, SECTION 6.0, BEST AVAILABLE RETROFIT TECHNOLOGY

SOUTH DAKOTA'S

REGIONAL HAZE

STATE IMPLEMENTATION PLAN

South Dakota Department of Environment and Natural Resources

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Executive Summary

The Department of Environment and Natural Resources (DENR) worked with the Western Regional Air Partnership (WRAP), states that were not members of WRAP, federal land managers, the Environmental Protection Agency (EPA), the regulated community, and others to develop this document as part of South Dakota's Regional Haze State Implementation Plan (SIP). This document along with the applicable Administrative Rules of South Dakota (ARSD) and the addition of ARSD, Chapter 74:36:21 will be South Dakota's Regional Haze State Implementation Plan and implemented by DENR to ensure South Dakota's Regional Haze Program meets the goal of achieving natural conditions in the Badlands and Wind Cave National Parks by 2064 as specified in Title 40 of the Code of Federal Regulations (CFR) §51.308.

Chapter 1 provides background information on the initial federal visibility protection program, describes the causes of visibility impairment, and describes the new federal regional haze program regulations. Chapter 2 provides information on South Dakota's two Class I areas. The two Class I areas are the Badlands National Park and Wind Cave National Park and both are located in the western third of South Dakota.

Chapter 3 describes the process DENR followed to determine natural conditions, baseline conditions, and the uniform rate of improvement for both Class I areas. Chapter 4 discusses the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring data for both Class I areas. This chapter looked at the aerosols that impact both Class I areas, what time of year they occur, and if they are increasing or decreasing over time.

Chapter 5 describes South Dakota's emission inventory for past, present, and future air emission inventories in South Dakota, what type of activities are emitting the air emissions, and if the air emissions are generated within South Dakota or from neighboring states and countries. Chapter 6 describes the BART review DENR conducted and establishes the BART requirements for the BART-eligible sources in South Dakota. The BART review covers an analysis to determine BART-eligible sources, a modeling analysis to determine if the BART-eligible source contributes to visibility impairment in a Class I area, and the establishment of BART for those BART-eligible sources that reasonably contribute to visibility impairment in any Class I area.

The BART review identified one electrical generating unit subject to the BART requirements. Otter Tail Power Company's Big Stone I facility determined that it reasonably contributes to visibility impairment in Class I areas. DENR determined the control equipment considered BART for Big Stone I is the existing baghouse, a semi-dry flue gas desulfurization system, and selective catalytic reduction. The installation of the new control equipment and establishment of BART emission limits, compliance demonstration, recordkeeping, and reporting requirements will be established in an air quality construction permit and eventually in Otter Tail Power Company's Title V air quality operating permit. The installation of the new control equipment and other requirements will be completed within five years of EPA's approval of South Dakota's Regional Haze State Implementation Plan.

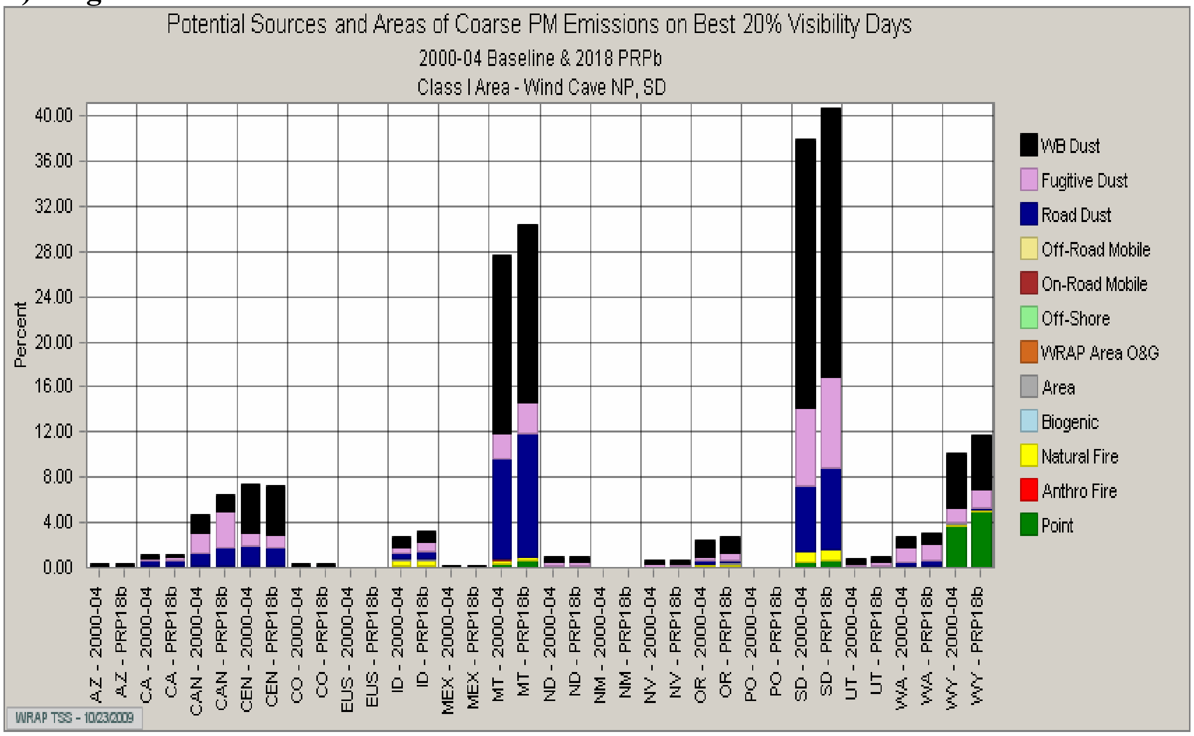
Chapter 7 discusses South Dakota's goals for demonstrating reasonable progress such as outlining existing rules that already help minimize air emissions that cause visibility impairment and the modeling WRAP conducted of the western United States to determine if states are meeting the reasonable progress goals in 2018. Sulfur dioxide emissions in South Dakota from 2002 through 2018 are expected to decline by 36%, nitrogen oxides emissions are expected to decline by 18%, organic carbon mass emissions are expected to decline by 6%, and elemental carbon emissions are expected to decline by 49%. Other states will also experience a reduction in air emissions that reasonably contribute to visibility impairment in Class I areas. Overall, sulfur dioxide emissions during the same time period are expected to decline by 26%, nitrogen oxide emissions are expected to decline by 29%, organic carbon mass are expected to decline by 6%, and elemental carbon emissions are expected to decline by 31%. These reductions are expected to demonstrate reasonable progress is being made to improve visibility at all Class I areas.

Chapter 8 describes South Dakota's long-term goals in achieving natural conditions by 2064. It also outlines DENR's proposed rules (ARSD, Chapter 74:36:21) to ensure new sources and modifications to existing sources will not reasonably contribute to visibility impairment at any Class I area. In addition, DENR will review, develop, and implement a Smoke Management Plan to address wildfires and prescribed fires.

Chapter 9 discusses DENR's monitoring plan for tracking our progress in achieving natural conditions by 2064. Chapter 10 describes the consultation DENR went through with federal land managers, states, and the public, how DENR responded to each comment, and their future involvement.

Chapter 11 describes the reviews and reporting DENR will perform to track South Dakota's progress in attaining natural conditions by 2064.

b) Regional Coarse Particulate Matter Contributions at Wind Cave



(WRAP TSS – http://vista.cira.colostate.edu/tss/)

6.0 Best Available Retrofit Technology (BART)

6.1 Bart-Eligible Sources

In accordance with 40 CFR § 51.308(e), South Dakota's State Implementation Plan is required to contain emission limitations representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I area. A BART-eligible source is an existing stationary facility that is any of the following stationary sources of air pollutant that was not in operation prior to August 7, 1962, was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any air pollutant. Fugitive emissions must be included in the potential to emit, to the extent quantifiable.

1. Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input,
2. Coal cleaning plants (thermal dryers),
3. Kraft pulp mills,
4. Portland cement plants,
5. Primary zinc smelters,
6. Iron and steel mill plants,
7. Primary aluminum ore reduction plants,
8. Primary copper smelters,

9. Municipal incinerators capable of charging more than 250 tons of refuse per day,
10. Hydrofluoric, sulfuric, and nitric acid plants,
11. Petroleum refineries,
12. Lime plants,
13. Phosphate rock processing plants,
14. Coke oven batteries,
15. Sulfur recovery plants,
16. Carbon black plants (furnace process),
17. Primary lead smelters,
18. Fuel conversion plants,
19. Sintering plants,
20. Secondary metal production facilities,
21. Chemical process plants,
22. Fossil-fuel boilers of more than 250 million British thermal units per hour heat input,
23. Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,
24. Taconite ore processing facilities,
25. Glass fiber processing plants, and
26. Charcoal production facilities.

In February 2004, DENR followed the procedures in 40 CFR Part 51, Appendix Y in identifying emission units at stationary facilities in South Dakota meeting the above categories, identifying the startup date of the emission units, comparing the potential emissions to the 250 tons per year cutoff, and identifying the emissions units and pollutants that constitute the BART-eligible sources. The following terms are defined below:

1. "In Operation" means engaged in activity related to the primary design function of the source. The date the unit is permitted is not important to meet this test because the focus is on actual operation of the unit;
2. "In Existence" means that the owner or operator has obtained all necessary preconstruction approvals or permits required by federal, state, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time;
3. "Date of Reconstruction" must occur during the August 7, 1962 to August 7, 1977 time period; and
4. "Potential to Emit" means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source. However, fugitive emissions, to the extent quantifiable, must be counted for the 26 categories.

In accordance with 40 CFR § 51.308(e)(1)(i), Table 6-1 provides a list of existing stationary facilities from the February 2004 analysis that may be considered a BART-eligible source and need further investigation to determine if they are subject to BART.

Table 6-1– List of BART-Eligible Sources [1]

Unit	Date	Maximum Capacity	Potential to Emit				BART Eligible
			TSP	SO_2	NOx	VOC	
Northern States Power Company – Sioux Falls							
#1 – Babcock boiler	1969	330 MMBtus/hr	7	1	795	2	Yes
#2 – Babcock boiler	1969	330 MMBtus/hr	7	1	795	2	Yes
#3 – Babcock boiler	1969	330 MMBtus/hr	7	1	795	2	Yes
Total =		**990 MMBtus/hr**	**21**	**3**	**2,385**	**6**	**Yes**
Pete Lien and Sons, Inc. – Rapid City							
#6 – Vertical kiln	1966	-	561	0	13	1	Yes
#7 – Pebble lime crusher	1970	-	1	0	0	0	Yes
#8 – Large hydrator	1965	-	97	0	0	0	Yes
#12 – Lime bagging	1963	-	48	0	0	0	Yes
Total =			707	0	13	1	**Yes**
Otter Tail Power Company – Big Stone I Power Plant							
#1 – Babcock boiler	1975	5,609 MMBtus/hr	300	19,863	17,179	125	**Yes**

[1] – "TSP" means total suspended particulate, "SO_2" means sulfur dioxide, "NOx" means nitrogen oxide, and "VOCs" means volatile organic compounds.

In accordance with 40 CFR Part 51, Appendix Y, the next step is to identify those BART-eligible sources that may "*emit any pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility*." For each source subject to BART, DENR is required to identify the best system of continuous emission control technology for each source after considering the following as specified in section 169A(g)(2) of the federal CAA:

1. Cost of compliance;
2. The energy and non-air quality environmental impacts of compliance;
3. Any existing pollution control technology in use at the source;
4. The remaining useful life of the source; and
5. The degree of visibility improvement which may reasonably be anticipated from the use of BART.

The results of the BART review are required to be submitted in the Regional Haze State Implementation Plan identifying the BART emission limitations and timeline for demonstrating compliance. The timeline for demonstrating compliance shall not exceed five years after EPA approves the Regional Haze State Implementation Plan. DENR may establish design, equipment, work practice or other operational standards when limitations on measurement technologies make emission standards infeasible.

6.1.1 Northern States Power Company – Sioux Falls

The three units at Northern States Power Company in Sioux Falls, South Dakota is considered fossil-fuel fired steam electric plant. The units were built in 1969 and have a maximum capacity greater than 250 million Btus per hour per unit. However, Northern States Power Company decommissioned these three units and they are no longer permitted to operate in Northern States Power Company's Title V air quality permit. Therefore, these three units at Northern States Power Company's Sioux Falls site are not subject to BART.

6.1.2 Pete Lien and Sons, Inc. – Rapid City

Pete Lien and Sons operates a limestone quarry operation and lime plant in northwest Rapid City. There are four operations that were identified in the February 2004 analysis, not in operation prior to August 7, 1962, and in existence on August 7, 1977. The four operations are a 1966 vertical kiln, 1970 pebble lime crusher, 1965 large hydrator, and 1963 lime bagging operation. Only the 1966 vertical kiln has the potential to emit over the 250 tons per year threshold.

As identified in Pete Lien and Sons' existing Title V air quality permit issued November 12, 2008, the 1970 pebble lime crusher was replaced with a 1982 pebble lime crusher and the 1963 bagging operation was replaced with a 2004 lime bagging operation. Therefore, these two units will not be evaluated further.

Pete Lien and Sons falls under the "lime plant" category listed above. DENR researched the definition of "lime plant" to determine if the large hydrator is included in the definition of a lime plant. DENR determined that typically the definition for the 26 categories coincides with the definitions under the New Source Performance Standards. Under 40 CFR Part 60, Subpart HH, a lime manufacturing plant means, "*…any plant which used a rotary lime kiln to produce lime product from limestone by calcinations.*" Based on this definition of a lime plant, Pete Lien and Sons would not be considered a lime plant because the kiln in question is a vertical kiln and not a rotary kiln. In addition, only the kiln would be considered a "lime plant".

DENR assumed the vertical kiln was considered a lime plant and on April 21, 2006, DENR requested that WRAP model Pete Lien and Sons emissions to determine if they would cause or contribute to any impairment of visibility in a Class I area. WRAP initiated this process by running CALMET/CALPUFF modeling using WRAP's "*CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States*," August 15, 2006. The basic assumptions in the protocol are:

1. Use of three years of modeling consisting of calendar year 2001, 2002 and 2003;
2. Visibility impacts due to emissions of sulfur dioxide, nitrogen oxide and primary particulate matter emissions were calculated. Unless a state provided speciated particulate matter emissions, all PM emissions were modeled as $PM_{2.5}$. In this case all PM emissions were modeled as $PM_{2.5}$;

3. Visibility was calculated using the original IMPROVE equation and annual average natural conditions; and
4. CALPUFF version 6.112 was used in the analysis.

The CALPUFF modeling procedures are outlined in WRAP's BART Modeling Protocol, which can be reviewed at the following website:

http://pah.cert.ucr.edu/aqm/308/bart/WRAP_RMC_BART_Protocol_Aug15_2006.pdf.

Table 6-2 provides a summary of the modeling outputs based on annual sulfur dioxide and nitrogen oxide emissions of 0.4 and 277 tons per year, respectively.

Table 6-2– WRAP's Modeling Results for Pete Lien and Sons [1]

Class I Area	State	Minimum Distance	Max Delta (dv)	99th (dv)	Days >0.5	Annual 98th percentile 2001	2002	2003
Badlands	SD	73 km	0.267	0.140	0	0.120	0.160	0.105
Boundary Waters	MN	946 km	0.014	0.007	0	0.005	0.003	0.003
Bridger	WY	489 km	0.021	0.003	0	0.001	0.002	0.001
Fitzpatrick	WY	501 km	0.018	0.002	0	0.001	0.001	0.001
Grand Teton	WY	570 km	0.005	0.001	0	0.000	0.000	0.000
Lostwood	ND	509 km	0.040	0.009	0	0.006	0.005	0.007
Medicine Lake	MT	488 km	0.030	0.011	0	0.006	0.005	0.010
North Absaroka	WY	487 km	0.008	0.002	0	0.001	0.001	0.001
Teton	WY	513 km	0.009	0.001	0	0.001	0.001	0.000
Theodore Roosevelt	ND	311 km	0.049	0.023	0	0.014	0.016	0.015
Ul Bend	MT	516 km	0.024	0.006	0	0.005	0.003	0.005
Voyageurs	MN	921 km	0.012	0.006	0	0.004	0.002	0.003
Washakie	WY	461 km	0.019	0.003	0	0.001	0.002	0.001
Wind Cave	SD	52 km	0.366	0.203	0	0.128	0.137	0.139
Yellowstone	WY	524 km	0.008	0.002	0	0.001	0.001	0.001

[1] - "dv" means deciview and "km" means kilometers.

The modeling conducted by WRAP demonstrated that Pete Lien and Sons did not cause or contribute to visibility impairment at a Class I area. After reviewing the modeling inputs, DENR determined the vertical kiln should be modeled again because of errors in the UTM coordinates and emission rates. However, before the modeling could be re-run, the vertical kiln was shutdown and dismantled in 2009.

Although Pete Lien and Sons' existing Title V air quality permit still identifies the vertical kiln as a unit, permit condition 1.1 specifies in the footnote of Table 1-1 that Pete Lien and Sons is required to shutdown and dismantle the vertical kiln before the initial startup of Unit #45. Pete Lien and Sons fulfilled this commitment by notifying DENR on March 13, 2009, that the vertical kiln was shutdown and dismantled. Therefore, Pete Lien and Sons' shutdown and dismantled the unit subject to BART and DENR did not re-model the vertical kiln.

6.1.3 Otter Tail Power Company – Big Stone I

Unit #1 at the Big Stone I Power Plant was built in 1975, has a maximum capacity greater than 250 million Btus per hour, and has the potential to emit greater than 250 tons per year of any air pollutant. The next step in this analysis is to determine if Unit #1's emissions may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area. On April 21, 2006, DENR requested that WRAP model Unit #1's emissions from Otter Tail Power Company's Big Stone I Power Plant.

WRAP initiated this process by running CALMET/CALPUFF modeling using WRAP's "CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States," August 15, 2006. The basic assumptions in the protocol are:

1. Use of three years of modeling of 2001, 2002 and 2003;
2. The sulfur dioxide, nitrogen oxide and particulate emission rates represent the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled, not including periods of startup, shutdown, or malfunctions;
3. Visibility impacts due to emissions of sulfur dioxide, nitrogen oxide and primary particulate matter emissions were calculated. Unless a state provided speciated particulate matter emissions, all PM emissions were modeled as $PM_{2.5}$;
4. Visibility was calculated using the original IMPROVE equation and annual average natural conditions; and
5. CALPUFF version 6.112 was used in the analysis.

The CALPUFF modeling procedures are outlined in WRAP's BART Modeling Protocol and can be reviewed at the following website:

http://pah.cert.ucr.edu/aqm/308/bart/WRAP_RMC_BART_Protocol_Aug15_2006.pdf.

Table 6-3 provides a summary of the modeling outputs based on annual sulfur dioxide and nitrogen oxide emissions of 12,409 and 15,580 tons per year, respectively. The annual sulfur dioxide and nitrogen oxide emissions were derived from WRAP's BART protocol identified above.

Table 6-3– WRAP's Modeling Results for Otter Tail Power Company Big Stone I [1]

Class I Area	State	Min Distance	Max Delta (dv)	99th (dv)	Days >0.5	Annual 98th percentile 2001	2002	2003
Badlands	SD	470 km	3.047	1.076	21	0.364	0.417	**0.683**
Boundary Waters	MN	431 km	1.653	1.133	63	**0.951**	**0.659**	**1.034**
Bridger	WY	1,041 km	0.147	0.003	0	0.001	0.001	0.000
Fitzpatrick	WY	1,050 km	0.079	0.005	0	0.001	0.001	0.000
Grand Teton	WY	1,112 km	0.029	0.003	0	0.001	0.001	0.000
Lostwood	ND	585 km	0.779	0.370	7	0.263	0.175	0.204

Class I Area	State	Min Distance	Max Delta (dv)	99th (dv)	Days >0.5	Annual 98th percentile 2001	2002	2003
Medicine Lake	MT	690 km	0.678	0.345	7	0.256	0.211	0.218
North Absaroka	WY	1,013 km	0.121	0.026	0	0.011	0.008	0.001
Teton	WY	1,052 km	0.049	0.008	0	0.004	0.002	0.001
Theodore Roosevelt	ND	555 km	2.061	0.840	27	**0.581**	0.443	**0.687**
Ul Bend	MT	902 km	0.840	0.196	3	0.089	0.065	0.043
Voyageurs	MN	438 km	1.658	0.915	52	**0.666**	**0.703**	**0.729**
Washakie	WY	1,006 km	0.090	0.018	0	0.007	0.005	0.001
Wind Cave	SD	572 km	1.545	0.631	13	0.224	0.263	0.261
Yellowstone	WY	1,049 km	0.068	0.018	0	0.009	0.004	0.001

[1] - "dv" means deciview and "km" means kilometers.

WRAP had determined that Big Stone I would be reasonably anticipated to contribute to an impairment of visibility at the Badlands National Park in South Dakota, Theodore Roosevelt National Park in North Dakota, and Boundary Waters Wilderness and Voyageurs National Park in Minnesota.

6.2 Otter Tail Power Company's Modeling Results

Otter Tail Power Company was notified of the results and requested an opportunity to verify the results after identifying several errors in actual emission rates and stack parameters. The department allowed Otter Tail Power Company to re-run the models using the correct emission rates and stack parameters. On March 19, 2008, Otter Tail Power Company submitted an individual source analysis using CALMET/CALPUFF; but after review by the state, EPA, and federal land managers (U.S. Fish and Wildlife Service, U.S. Forest Service and National Park Service) it was determined that a BART modeling protocol should be submitted and approved by all parties, Otter Tail Power Company would run the model using the approved protocol, and submit before Otter Tail Power Company's results could be approved.

Otter Tail Power Company submitted the BART modeling protocol on January 16, 2009. After several conference calls and discussions, a revised protocol identified as June 2009, was submitted July 1, 2009. After several submittals and conference calls, Otter Tail Power Company committed to make the following changes to the protocol in an email dated August 31, 2009:

1. Although Otter Tail Power Company attached the CALMET switches it would use, it committed to using the CALMET switches recommended and approved by EPA and Federal Land Managers (FLMs) dated August 20, 2009. However, to ensure the most up-to-date CALMET switches are used, DENR is requiring Otter Tail Power Company to use the CALMET switches identified in EPA's memorandum dated August 31, 2009, from Tyler J Fox, Group Leader, Air Quality Modeling Group, to EPA Regional Modeling Contacts. The date on the listing of CALMET switches is August 28, 2009. The memorandum may be viewed in Attachment C.

2. Otter Tail Power Company committed to use the CALPUFF switches that Penny Shamblin, with Hunton and Williams, submitted to DENR by email on August 19, 2009. Although the document contains CALMET switches, only the CALPUFF switches (see Attachment D) in this email will be used by Otter Tail Power Company in the BART analysis. The CALMET switches mentioned above will be the ones used in the analysis.
3. Otter Tail Power Company proposes to revise the June 2009 modeling protocol by using a 12 kilometer MM5 grid and a 4 kilometer CALMET grid rather than the 4 kilometer MM5 grid and 4 kilometer CALMET grid identified in the June 2009 modeling protocol. DENR reviewed other acceptable modeling protocols and is acceptable to this change.
4. Although Otter Tail Power Company may run POSTUTIL option MNITRATE=2 for its own purposes, the modeling results DENR will accept for the BART analysis will be MNITRATE=1.

The CALPUFF switches Otter Tail Power Company is recommending contains five switches that are different then those recommended by EPA as defaults. The following identifies the variable, EPA's default, recommended default by Otter Tail Power Company, and DENR's response:

1. "NSPEC" – Identifies the number of species modeled. The EPA default is 5 and Otter Tail Power Company is proposing 11, which follows the FLM guidance on particle speciation and size. DENR is agreeable to this change.
2. "NSE" – Number of species emitted. The EPA default is 3 and Otter Tail Power Company is proposing 9.
3. "MSPLIT" – Allows puffing. The EPA default is 0 (No) and Otter Tail Power Company is proposing 1 (Yes). Puff splitting in necessary due to the distance from Big Stone I to a federal Class I area. DENR is agreeable to this change.
4. "MESHDN" – Grid receptor spacing. The EPA default is 1; however, Otter Tail Power Company is stating this is "Not Applicable". DENR is agreeable to this change.
5. "BCKNH3" – Ammonia background. The EPA default is 10 parts per billion and Otter Tail Power Company is recommending 1 part per billion. During the June 3, 2009, conference call, EPA stated it was okay with this change. DENR is agreeable to this change.

On September 18, 2009, the department determined that Otter Tail Power Company's BART modeling protocol as identified above. See Appendix A for the approval letter and the BART modeling protocol dated June 2009.

The modeling results identified that Otter Tail Power Company's Big Stone I Power Plant would be reasonably anticipated to contribute to an impairment of visibility at the Boundary Waters and Voyageurs federal Class I areas in northern Minnesota and the Isle Royale federal Class I area in Michigan. The reasonably anticipated to contribute to an impairment is based on visibility impacts greater than 0.5 deciview based on the 98^{th} percentile at the three federal Class I areas. See Appendix B for the modeling report dated October 2009, and Table 6-4 for a summary of the modeling results.

Table 6-4– Otter Tail Power Company's Modeling Results for Big Stone I [1]

Class I Area	State	Min Distance	Max Delta (dv)	99th (dv)	98th (dv)
Badlands	SD	470 km	2.202	0.698	**0.481 (0.5)**
Boundary Waters	MN	431 km	3.574	1.351	**1.079 (1.1)**
Lostwood	ND	585 km	1.110	0.722	0.409 (0.4)
Theodore Roosevelt	ND	555 km	2.232	0.772	**0.459 (0.5)**
Voyageurs	MN	438 km	2.162	1.376	**0.724 (0.7)**
Wind Cave	SD	572 km	1.671	0.591	0.325 (0.3)
Isle Royale	MI	1,049 km	1.806	0.789	**0.665 (0.7)**

[1] - "dv" means deciview and "km" means kilometers.

Otter Tail Power Company results did not match up entirely with the modeling conducted by WRAP. In particular, Otter Tail Power Company's modeling also showed that Big Stone I would reasonably contribute to impairment at the Isle Royale National Park in Michigan. DENR believes Otter Tail Power Company's modeling best represent the visibility impacts from Big Stone I since the original modeling did not have the correct emission rates and stack parameters and the CALPUFF modeling conducted by Otter Tail Power Company included puff splitting, which helps improve the accuracy of the model when used for great distances.

In accordance with the 40 CFR Part 51, Appendix Y, DENR used a contribution threshold of 0.5 deciviews for determining if Otter Tail Power Company's Big Stone I facility is subject to BART. The guideline provides the state the discretion to set a threshold below 0.5 deciviews if "the location of a large number of BART-eligible sources within the state and proximately to a Class I area justifies this approach. The discretion was based on the following factors:

1. It equates to the 5 percent extinction threshold for new sources under the PSD New Source Review rules;
2. It is consistent with the threshold selected by other states in the west, which all selected 0.5 deciviews; and
3. It represents the limit of perceptible change.

DENR chose the 0.5 deciview threshold because there is only one source that is BART-eligible and it is greater than 300 kilometers from any Class I area. Therefore, DENR will establish this threshold in its proposed ARSD Chapter 74:36:21 – Regional Haze Program. Otter Tail Power Company's Big Stone I power plant exceeded this threshold and is subject to BART. In accordance with 40 CFR § 51.308(e)(1)(i), the only source subject to BART in South Dakota is Otter Tail Power Company's Big Stone I facility.

In accordance with 40 CFR § 51.308(e)(1)(ii), DENR requested that Otter Tail Power Company complete a Case-by-Case BART analysis, which includes determining the visibility improvements expected at each of these Class I areas (see Appendix C).

6.3 Otter Tail Power Company's Case-by-Case BART Analysis

In accordance with 40 CFR 51.301, Best Available Retrofit Technology (BART) is defined as *"an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."*

In accordance with 40 CFR § 51.308(e)(1)(ii)(B), the determination of BART for fossil fuel fired power plants having a total generating capacity greater than 750 megawatts must be made pursuant to the guidelines in Appendix Y of this part (Guidelines for BART Determinations under the Regional Haze Rule). Appendix Y identifies a five step process in determining BART. The five steps are as follows:

1. STEP 1—Identify All Available Retrofit Control Technologies: In identifying ''all'' options, one should identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology. The list is complete if it includes the maximum level of control each technology is capable of achieving. Where a New Source Performance Standard (NSPS), under 40 CFR Part 60, exists for a source category, one should include a level of control equivalent to the NSPS as one of the control options;
2. STEP 2—Eliminate Technically Infeasible Options: One evaluates the technical feasibility of the control options identified in Step 1. One should document a demonstration of technical infeasibility and should explain, based on physical, chemical, or engineering principles, why technical difficulties would preclude the successful use of the control option on the emissions unit under review. One may then eliminate such technically infeasible control options from further consideration in the BART analysis;
3. STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies: One evaluates the control effectiveness of all the technically feasible control alternatives identified in Step 2 for the pollutant and emissions unit under review. Two key issues in this process include: (1) Make sure that you express the degree of control using a metric that ensures an ''apples to apples'' comparison of emissions performance levels among options; and (2) Give appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels;
4. STEP 4—Evaluate Impacts and Document the Results: Once the available and technically feasible control technology options are identified, one should conduct the following analyses when you make a BART determination: (1) Impact analysis part 1 – costs of compliance; (2) Impact analysis part 2 – energy impacts, (3) Impact analysis part 3 – non-air quality environmental impacts; and (4) Impact analysis part 4 – remaining useful life; and

5. STEP 5—Evaluate Visibility Impacts: One should evaluate the net visibility improvement form the available and technically feasible control technology options. This is accomplished by modeling the pre-control and post-control emission rates according to an accepted methodology.

In determining what is considered BART, Appendix Y identifies that the state should develop a chart (or charts) displaying each of the alternatives and include: (1) Expected emission rate (e.g., tons per year, pounds per hour); (2) Emissions performance level (e.g., percent pollutant removed, emissions per unit product, pounds per million Btus, parts per million); (3) Expected emissions reductions (e.g., tons per year); (4) Costs of compliance (e.g., total annualized costs in dollars, cost effectiveness (dollar per ton), incremental cost effectiveness (dollar per ton), any other cost-effectiveness measures (dollar per deciview)); (5) Energy impacts; (6) Non-air quality environmental impacts; and (7) Modeled visibility impacts.

Otter Tail Power Company's Big Stone I facility does not have a total generating capacity greater than 750 megawatts. Therefore, DENR is not required to follow these guidelines. As such, DENR will follow the steps identified in Appendix Y with some slight differences. For example, in identifying the available control technologies, DENR is not listing any of the permutations of the control levels for each identified control technology as suggested by EPA's guidance. DENR will use the initial step to identify control technologies without including the control levels. Step 3 is used to evaluate the control effectiveness or permutations of the control levels for those control technologies that are considered feasible to install or maintain as identified in Step 2.

6.3.1 Particulate BART Review

6.3.1.1 Particulate Control Technologies

Step 1 requires the identification of all available retrofit control technologies. The particulate matter emissions from fossil-fuel fired units can be categorized as either filterable or condensable particulate. The filterable particulate matter exists as a solid or liquid particle in the exhaust of a boiler as it leaves the stack. As such, the filterable particulate may be collected by placing a control device in the flue gas stream prior to the stack. Condensable particulates are emitted out the stack in a gaseous state but rapidly condense into particles when released into the atmosphere and cooled. Therefore, condensable particulates may not be readily collected by placing a control device in the stack.

Those control technologies being reviewed under Step 1 are those that would control the filterable particulate matter. Otter Tail Power Company identified the following control options for particulate matter.

1. Existing fabric filter (baghouse);
2. New fabric filter (baghouse);
3. Compact hybrid particulate collector; and
4. Electrostatic precipitator.

DENR also identified two more control technologies that may be used to control particulate emissions and are listed below:

1. Wet scrubber; and
2. Cyclone(s)/Multicyclone(s).

6.3.1.2 Technically Feasible Particulate Control Technologies

Step 2 requires the elimination of any control technologies identified in Step 1 that are technically infeasible. A compact hybrid particulate collector is a combination of an electrostatic precipitator and a baghouse in series. The compact hybrid particulate collector is generally operated with a higher air-to-cloth ratio than a typical baghouse. Since Otter Tail Power Company already has a baghouse installed at Big Stone I, Otter Tail did not further consider the compact hybrid particulate collector.

Even though Otter Tail Power Company identified a reason for not selecting the compact hybrid particulate collector, the reasoning does not identify that the technology is infeasible to install. Since both an electrostatic precipitator and a baghouse are both technically feasible options and without further evidence, DENR considers the compact hybrid particulate collector as a feasible control technology.

DENR determined that the following particulate control technologies were feasible for Otter Tail Power Company:

1. Existing fabric filter (baghouse);
2. New fabric filter (baghouse);
3. Compact hybrid particulate collector;
4. Electrostatic precipitator;
5. Wet scrubber; and
6. Cyclone(s)/Multicyclone(s).

6.3.1.3 Particulate Control Effectiveness

Step 3 requires the evaluation of control effectiveness for each control technology. DENR evaluated the control effectiveness by comparing the effectiveness in Table 6.5.

Table 6-5 – Comparison of Control Effectiveness for Particulate Controls

		Emission Rate		**Control Efficiency**	
		Otter Tail [1]	**RBLC [3]**	**PFDR [4]**	**IEA [5]**
Rank	**Control**	**(lbs/MMBtus) [2]**	**(lbs/MMBtus) [2]**	**(%)**	**(%)**
#1	**Baghouse**	0.015	0.010 to 0.03	95 to 99.9	>99 to >99.9999
#2	**Electrostatic Precipitator**	0.015	0.015 to 0.03	80 to 99.5	>99 to >99.99
#3	**COHPAC [6]**	Not Provided	0.015	Not Identified	Not Identified

Rank	Control	Emission Rate		Control Efficiency	
		Otter Tail [1]	RBLC [3]	PFDR [4]	IEA [5]
		(lbs/MMBtus) [2]	(lbs/MMBtus) [2]	(%)	(%)
#4	**Wet Scrubber(s)**	Not Provided	Not Identified	75 to 99	90 to 99.9
#5	**Cyclone(s)/ Multicyclone(s)**	Not Provided	Not Identified	50 to 95	75 – 99

[1] – The identified emission rates were identified in Otter Tail Power Company's BART analysis;
[2] – "lbs/MMBtus" means pounds per million British thermal units;
[3] – The identified emission rates were obtained from EPA's Reasonable Achievable Control Technology, Best Available Control Technology, and Lowest Achievable Emission Rate Clearinghouse (RBLC) considering data for permits issued after calendar year 2000;
[4] – The control efficiencies, in percent removal, are derived from page 473 of "Particulates and Fine Dust Removal Process and Equipment by Marshal Sittig";
[5] – The control efficiencies, in percent removal, are derived from the IEA Clean Coal Centre's Webpage at http://www.iea-coal.org.uk/site/ieacoal/home; and
[6] – "COHPAC" means Compact Hybrid Particulate Collector.

6.3.1.4 Particulate Control Technology Impacts

In Step 4, DENR looked at impacts associated with the control alternatives such as cost of compliance, energy impacts, non-air quality environmental impacts, and the remaining useful life of the project. These impacts are intended to provide rational in choosing between the alternative control options when determining what is considered BART. Otter Tail Power Company already has installed and is operating a baghouse, which is the top particulate control technology. Therefore, there is no additional compliance cost, energy impacts, etc. that Otter Tail Power Company would have to endure. As such, no additional impacts analysis will be conducted to determine the appropriate controls for particulate matter.

6.3.2 Sulfur Dioxide BART Review

6.3.2.1 Sulfur Dioxide Control Technologies

Step 1 requires the identification of all available retrofit control technologies. Otter Tail Power Company identified the following control options for sulfur dioxide:

1. Fuel switching;
2. Semi-dry flue gas desulfurization; and
3. Wet flue gas desulfurization.

DENR also identified the following control technologies that may be used to control sulfur dioxide emissions:

1. Coal cleaning;
2. Coal upgrading;
3. Hydrated lime injection; and

4. Emerging control technologies such as Enviroscrub, Electro catalytic oxidation, and Airborne process.

6.3.2.2 Technically Feasible Sulfur Dioxide Control Technologies

Fuel switching is a viable method to reduce sulfur dioxide emissions by switching to a fuel with lower sulfur content. Otter Tail Power Company's Big Stone facility's primary fuel source is subbituminous coal obtained from the Powder River Basin in Wyoming. Powder River Basin subbituminous coal has one of the lowest sulfur contents available in the United States. As such, Otter Tail Power Company has already implemented fuel switching.

Coal cleaning is typically performed by physical gravimetric separation which is capable of reducing sulfur, ash and impurities from the coal. The effectiveness of gravimetric separation is dependent on the ash content and the distribution of fuel bound sulfur between organic and inorganic. If the sulfur compounds are predominantly inorganic materials, then coal cleaning is fairly effective, but if the sulfur compounds are predominantly organic materials, then coal cleaning is not effective. Physical cleaning or gravimetric separation may be effective with bituminous coals that contain high levels of inorganic sulfur and ash. However, gravimetric coal cleaning is not technically feasible for low sulfur, low ash, and low inorganic-sulfur content coal such as the coal from the Powder River Basin in Wyoming. Otter Tail Power Company's Big Stone facility's primary fuel source is subbituminous coal obtained from the Powder River Basin in Wyoming. As such, coal cleaning is not a technical feasible option for Otter Tail Power Company.

Coal upgrading such as a process developed by Evergreen Energy (formerly KFx) called the K-Fuel process enriches the coal by utilizing high pressure and temperature conditions to reduce moisture and inorganic materials. Typically, the K-Fuel process is utilized to reduce the moisture content and increase the coal heating value, however, the process may remove some sulfur compounds. Evergreen Energy constructed a K-Fuel production facility in Gillette, Wyoming which may produce approximately 750,000 tons per year of K-Fuel. Otter Tail Power Company burned approximately 2,268,000 tons of coal in 2008. As such, coal upgrading is not a technically feasible option for Otter Tail Power Company because there is not enough being produced to supply Otter Tail Power Company's needs. In addition, based on Evergreen Energy's webpage, this facility has been idle since calendar year 2008.

Hydrated lime injection is a system that injects hydrated lime prior to the particulate collection system. The hydrated lime absorbs the sulfur dioxide and is collected in the particulate control device. Hydrated lime is also referred to as calcium hydroxide. The sulfur dioxide reacts with the calcium hydroxide to form calcium sulfate or calcium sulfite. Fly ash from the Powder River Basin has a calcium content of up to 30 percent. Since the Powder River Basin coal is already providing additional calcium to adsorb sulfur dioxide, the hydrated lime will not likely provide additional sulfur dioxide removal. Otter Tail Power Company's primary fuel source is subbituminous coal obtained from the Powder River Basin in Wyoming. As such, hydrated lime injection is not considered a technically feasible option for Otter Tail Power Company since the concept is already taking place by using Power River Basin coal.

Emerging control technologies such as Enviroscrub, Electro catalytic oxidation, and the Airborne process have not been commercially available and have not been demonstrated for long-term levels of performance. As noted in 40 CFR Part 51, Appendix Y, a control technology needs to be commercially available to be considered technically feasible. As such these emerging technologies are not considered technically feasible options for Otter Tail Power Company.

DENR determined that the following sulfur dioxide control technologies were feasible for Otter Tail Power Company:

1. Semi-dry flue gas desulfurization; and
2. Wet flue gas desulfurization.

6.3.2.3 Sulfur Dioxide Control Effectiveness

Step 3 requires the evaluation of control effectiveness for each control technology. DENR evaluated the control effectiveness by comparing the effectiveness in Table 6.6.

Table 6-6 – Comparison of Control Effectiveness for Sulfur Dioxide Controls

Rank	**Control**	**Emission Rate**			**Control Efficiency**
		Otter Tail [1]	**RBLC [3]**	**Basin [4]**	**EPA [5]**
		(lbs/MMBtus) [2]	**(lbs/MMBtus) [2]**	**(lbs/MMBtus) [2]**	**(%)**
#1	**Wet Flue Gas Desulfurization**	0.043 to 0.15	0.1 to 0.167	0.05	90 to 98
#2	**Semi-Dry Flue Gas Desulfurization**	0.09 to 0.15	0.038 to 0.16	0.07	80 to 90

[1] – The identified emission rates were identified in Otter Tail Power Company's BART analysis;
[2] – "lbs/MMBtus" means pounds per million British thermal units;
[3] – The identified emission rates were obtained from EPA's Reasonable Achievable Control Technology, Best Available Control Technology, and Lowest Achievable Emission Rate Clearinghouse (RBLC) considering data for permits issued after calendar year 2000;
[4] – The emission rates are based on the BACT analysis provided by Basin Electric Power Cooperative's proposed NextGen project in South Dakota; and
[5] – The control efficiencies, in percent removal, are from EPA's "Air Pollution Control Technology Fact Sheet on Flue Gas Desulfurization Systems".

6.3.2.4 Sulfur Dioxide Control Technology Impacts

Step 4 requires DENR to look at impacts associated with the control alternatives such as cost of compliance, energy impacts, non-air quality environmental impacts, and the remaining useful life of the project. These impacts are intended to provide rational in choosing between the alternative control options when determining what is considered BART.

Otter Tail Power Company identified cost estimates for each of the control options. In addition, Otter Tail Power Company identified cost estimated for two different operating scenarios for each of the two control alternatives. Table 6-7 summarizes Otter Tail Power Company's estimated costs.

In 40 CFR Part 51, Appendix Y – Guidelines for BART Determination Under the Regional Haze Rule, in the section titled "How should I determine visibility impacts in the BART determination" it notes that the model should use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). The 18,000 tons per year of sulfur dioxide is based on the highest average 24-hour average emission rate (4,832 pounds per hour) for calendar years 2001 through 2003 and operating 85% of the time or 7,746 hours per year. Based on the BART guidelines, the baseline emissions are 18,000 tons per year.

Table 6-7 – Comparison of Control Effectiveness for Sulfur Dioxide Controls

Control Option	Capital Cost	O&M [1]	Annual Cost [2]	Reduction [3]	Cost Effectiveness [4]
WFGD #1 [5]	$171,800,000	$9,600,000	$29,050,000	17,100	$1,699
WFGD #2 [6]	$171,800,000	$9,490,000	$28,900,000	14,870	$1,944
SDFGD #1 [7]	$141,300,000	$7,660,000	$23,570,000	16,120	$1,462
SDFGD #2 [8]	$141,300,000	$7,480,000	$23,330,000	14,870	$1,569

[1] – O&M represents the operational and maintenance cost estimate for the control alternative;
[2] – Annual cost is the annualized cost for each control alternative taking into account both the capital and operational and maintenance costs;
[3] – Reduction represents the amount of sulfur dioxide reduced in tons per year annual from the baseline level of 18,000 tons of sulfur dioxide per year;
[4] – Cost Effectiveness represents the annualized cost divided by the identified emission reductions (dollar per ton);
[5] – WFGD #1 represents a wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[6] – WFGD #2 represents a wet flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[7] – SDFGD #1 represents a semi-dry flue gas desulfurization system meeting an emission rate of 0.9 pounds per million British thermal units; and
[8] – SDFGD #2 represents a semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units.

Otter Tail Power Company did not identify the cost effectiveness on a dollar per visibility reduction. DENR considered this cost effectiveness in Step 5 of the analysis.

Otter Tail Power Company identified the energy impacts cost associated for each of the control options. Table 6-8 summarizes Otter Tail Power Company's estimated energy impacts.

Table 6-8 – Estimated Energy Impacts for Sulfur Dioxide Controls

Control	Energy Demand	Percent of Generation
Wet Flue Gas Desulfurization	9,500 kilowatts	2.0 percent
Semi-Dry Flue Gas Desulfurization	3,325 kilowatts	0.7 percent

The non-air quality environmental impacts of the two control alternatives include the solid and aqueous waste streams. The semi-dry flue gas desulfurization system would be installed upstream of the existing baghouse. The baghouse would be used to collect the injected lime and reacted sulfur dioxide emissions along with other existing particulate matter emissions. Otter Tail Power Company did not identify how much additional particulate matter would be collected by the baghouse due to the use of the semi-dry flue gas desulfurization system. At this time, it is assume the additional material collected in the baghouse is negligible compared to the existing collection. Otter Tail Power Company estimates that the wet flue gas desulfurization system would generate an additional 44,700 tons of gypsum solids which would need to be properly disposed.

In conducting its cost analysis, Otter Tail Power Company used 30 years as the life expectancy averaging period for the control alternatives. Since the useful life of Otter Tail Power Company's Big Stone I facility is expected to be longer than 30 years, there is no difference between the control options based on useful life.

6.3.3 Nitrogen Oxide BART Review

6.3.3.1 Nitrogen Oxide Control Technologies

Step 1 requires the identification of all available retrofit control technologies. Otter Tail Power Company identified the following control options for nitrogen oxide:

1. Low-nitrogen oxide burners (LNBs);
2. Over-fire air (OFA);
3. Separated over-fire air (SOFA);
4. Selective non-catalytic reduction (SNCR);
5. Rich reagent injection (RRI); and
6. Selective catalytic reduction (SCR).

DENR also identifies the following control technologies that may be used to control nitrogen oxide emissions:

1. Flue-gas recirculation;
2. Oxygen enhanced combustion;
3. Catalytic absorption/oxidation;
4. Gas reburn; and
5. Emerging control technologies such as Enviroscrub, Electro-catalytic oxidation, NOxStar, and Cascade processes.

6.3.3.2 Technically Feasible Nitrogen Oxide Control Technologies

Low-nitrogen oxide burners limit nitrogen oxide formation by controlling the stoichiometric and temperature profiles of the combustion process. Low-nitrogen oxide burners attempt to delay the complete mixing of fuel and air as long as possible within the constraints of the furnace design. This is the reason flames from low-nitrogen oxide burners are longer than conventional burners. Cyclone furnace's length and diameter are not designed with sufficient size to allow for low-nitrogen oxide burners to be installed allowing stable combustion. As such, low-nitrogen oxide burners are not considered a technically feasible option for Otter Tail Power Company.

Flue-gas recirculation reduces the formation of thermal nitrogen oxide emissions in a boiler by limiting the amount of oxygen available for oxidation in the fuel rich zone of the boiler. Flue-gas recirculation is not known to reduce nitrogen oxide emissions any further when added with an over-fire air system. Therefore, Otter Tail Power Company did not conduct any further review of flue-gas recirculation. However, this reasoning does not justify that flue-gas recirculation is not a feasible technology to consider. Therefore, DENR will consider the flue-gas recirculation as a feasible control technology.

Catalytic absorption/oxidation such as SCONOx or EMx systems is a nitrogen oxide control technology that utilizes a proprietary catalytic oxidation and absorption technology which oxidizes nitrogen oxide (NO) and carbon monoxide (CO) to nitrogen dioxide (NO2) and carbon dioxide (CO2), respectively. The nitrogen dioxide is then absorbed onto an absorption media while carbon dioxide is released to the atmosphere. Once the absorption media becomes saturated, the nitrogen dioxide is desorbed and treated by a proprietary catalyst. The SCONOx system is being considered as a cross over technology to coal-fired boilers, but to date has only been applied to "clean flue gas" systems such as natural-gas fired combustions turbines. The catalytic absorption/oxidation system requires a high operating temperature and low particulate loading. Therefore, the system would have to be installed after the particulate control device and require a flue gas reheater. DENR was unable to find a coal-fired system that was using a catalytic absorption/oxidation system or find that this system was being marketed commercially for coal fired boilers. As noted in 40 CFR Part 51, Appendix Y, a control technology needs to be commercially available to be considered technically feasible. As such the catalytic absorption/oxidation system is not considered a technically feasible option for Otter Tail Power Company.

Gas reburning is a nitrogen oxide control technology that uses a second combustion zone following the primary combustion zone in the boiler. In a cyclone boiler, such as the one being operated at Otter Tail Power Company's Big Stone I facility, burning the coal produces molten slag along the cyclone barrels. The molten slag catches subsequent coal until the combustion is complete. Generally, cyclone burners operate near the slag-tapping limits. Therefore, using natural gas or another fuel source as the reburn fuel may inhibit the molten slag formation. In addition, by trying to lower the air to fuel ratio more than achieved by the existing over-fire air systems may cause slag "freezing" at low load levels. As such gas reburn is not considered a technically feasible option for Otter Tail Power Company.

Oxygen enhanced combustion is a nitrogen oxide combustion control technology that reduces the formation of thermal nitrogen oxides in the boiler. Developed by Praxair Technology Inc., this method uses oxygen in the burner instead of air to achieve additional nitrogen oxide reductions. To date, the largest demonstration of this technology is a 30 megawatt pilot demonstration at Babcock and Wilcock's Clean Environmental Development facility in Alliance, Ohio. As noted on Babcock and Wilcock's website - http://www.babcock.com/, the project was a pilot test of the technology and the next step is to demonstrate the technology at a commercial scale. As noted in 40 CFR Part 51, Appendix Y, a control technology needs to be commercially available to be considered technically feasible. As such the oxygen enhanced combustion is not considered a technically feasible option for Otter Tail Power Company.

Emerging control technologies such as Enviroscrub, Electro catalytic oxidation, and the Airborne process have not been commercially available and have not been demonstrated for long-term levels of performance. As noted in 40 CFR Part 51, Appendix Y, a control technology needs to be commercially available to be considered technically feasible. As such these emerging technologies are not considered technically feasible options for Otter Tail Power Company.

DENR determined that the following nitrogen oxide control technologies were feasible for Otter Tail Power Company:

1. Over-fire air (OFA);
2. Separated over-fire air (SOFA);
3. Selective non-catalytic reduction (SNCR);
4. Rich reagent injection (RRI);
5. Selective catalytic reduction (SCR) ; and
6. Flue-gas recirculation.

6.3.3.3 Nitrogen Oxide Control Effectiveness

Step 3 requires the evaluation of control effectiveness for each control technology. DENR evaluated the control effectiveness by comparing the effectiveness in Table 6.9.

Table 6-9 – Comparison of Control Effectiveness for Nitrogen Oxide Controls

		Emission Rate			**Control Efficiency**	
		Otter Tail [1]	**RBLC** [3]	**Basin** [4]	**EPA** [5]	**IEA** [6]
Rank	**Control**	**(lbs/MMBtus)** [2]	**(lbs/MMBtus)** [2]	**(lbs/MMBtus)** [2]	**(%)**	**(%)**
#1	**SCR and SOFA** [7]	0.10	0.05 to 0.1	0.05	35 to 90	80 to 90
#2	**RRI, SNCR and SOFA** [8]	0.20	0.07 to 0.15	0.10	35 to 90	30 to 50
#3	**SNCR and SOFA** [9]	0.35	0.07 to 0.15	0.10	35 to 90	30 to 50
#4	**Separated over-fire air**	0.50	Not Identified	Not Identified	30 to 70	Not Identified

Rank	Control	Emission Rate			Control Efficiency	
		Otter Tail [1]	RBLC [3]	Basin [4]	EPA [5]	IEA [6]
		(lbs/MMBtus) [2]	(lbs/MMBtus) [2]	(lbs/MMBtus) [2]	(%)	(%)
#5	**Over-fire air**	0.65	Not Identified	Not Identified	30 to 70	Not Identified
#6	**Flue Gas Recirculation**	Not Identified	Not Identified	Not Identified	30 to 70	Not Identified

[1] – The identified emission rates were identified in Otter Tail Power Company's BART analysis;
[2] – "lbs/MMBtus" means pounds per million British thermal units;
[3] – The identified emission rates were obtained from EPA's Reasonable Achievable Control Technology, Best Available Control Technology, and Lowest Achievable Emission Rate Clearinghouse (RBLC) considering data for permits issued after calendar year 2000;
[4] – The emission rates are based on the BACT analysis provided by Basin Electric Power Cooperative's proposed NextGen project in South Dakota which is for a new pulverized-fired boiler equipped with a low-NOx burner combustion technology. The emission rates were primarily based on if the system used selective catalytic reduction or selective non-catalytic reduction;
[5] – The emission rates are from page 27 of the EPA's Technical Bulletin – *"Nitrogen Oxides; Why and How they are Controlled"*.
[6] – The emission rates were obtained from the IEA Clean Coal Centre's Webpage - http://www.iea-coal.org.uk/site/ieacoal/home. The emission rates were primarily based on if the system used selective catalytic reduction or selective non-catalytic reduction.
[7] – SCR and SOFA refers to selective catalytic reduction and separated over-fire air;
[8] – RRI, SNCR, and SOFA refers to rich reagent injection, selective non-catalytic reduction and separated over-fire air, respectively; and
[9] – SNCR and SOFA refers to selective non-catalytic reduction and separated over-fire air.

6.3.3.4 Nitrogen Oxide Control Technology Impacts

Step 4 requires DENR to look at impacts associated with the control alternatives such as cost of compliance, energy impacts, non-air quality environmental impacts, and the remaining useful life of the project. These impacts are intended to provide rational in choosing between the alternative control options when determining what is considered BART.

Otter Tail Power Company identified cost estimates for five control options. Table 6-10 summarizes Otter Tail Power Company's estimated costs.

In 40 CFR Part 51, Appendix Y – Guidelines for BART Determination Under the Regional Haze Rule, in the section titled "How should I determine visibility impacts in the BART determination" it notes that the model should use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). The 18,000 tons per year of nitrogen oxide is based on the highest average 24-hour average emission rate (4,855 pounds per hour) for calendar years 2001 through 2003 and operating 85% of the time or 7,746 hours per year. Based on the BART guidelines, the baseline emissions are 18,000 tons per year.

Table 6-10 – Comparison of Control Effectiveness for Nitrogen Oxide Controls

Control Option	Capital Cost	O&M [1]	Annual Cost [2]	Reduction [3]	Cost Effectiveness [4]
SCR and SOFA [5]	$81,800,000	$4,110,000	$13,210,000	16,000	$825
RRI, SNCR and SOFA [6]	$16,200,000	$7,260,000	$11,390,000	13,910	$818
SNCR and SOFA [7]	$11,900,000	$2,120,000	$3,990,000	10,780	$197
SOFA [8]	$4,800,000	$152,000	$650,000	7,640	$85
Over-fired air	$0	$106,000	$140,000	4,510	$31

[1] – O&M represents the operational and maintenance cost estimate for the control alternative;
[2] – Annual cost is the annualized costs for each control alternative taking into account both the capital and operational and maintenance costs;
[3] – Reduction represents the amount of nitrogen oxide reduced in tons per year annual from the baseline level of 18,000 tons of nitrogen oxide per year;
[4] – Cost Effectiveness represents the annualized cost divided by the identified emission reductions (dollar per ton);
[5] – SCR and SOFA refers to selective catalytic reduction and separated over-fire air;
[6] – RRI, SNCR, and SOFA refer to rich reagent injection, selective non-catalytic reduction and separated over-fire air;
[7] – SNCR and SOFA refers to selective non-catalytic reduction and separated over-fire air; and
[8] – SOFA refers to separated over-fire air.

Otter Tail Power Company did not identify a cost effectiveness on a dollar per visibility reduction. DENR considered this cost effectiveness in Step 5 of the analysis.

Otter Tail Power Company identified the energy impacts cost associated for each of the control options. Table 6-11 summarizes Otter Tail Power Company's estimated energy impacts.

Table 6-11 – Estimated Energy Impacts for Nitrogen Oxide Controls

Control	Energy Demand	Percent of Generation
Selective catalystic reduction and Separated over-fire air	400 to 1,000 kilowatts	Less than 0.2 percent
Rich reagent injection, Selective non-catalytic reduction and Separated over-fire air	150 to 400 kilowatts	Less than 0.1 percent
Selective non-catalytic reduction and Separated over-fire air	150 to 400 kilowatts	Less than 0.1 percent
Separated over-fire air	1 kilowatt	Negligible
Over-fire air	1 kilowatt	Negligible

The over-fire air and the separated over-fire air will increase the amount of unburned carbon in the flyash, which will increase the amount of flyash that needs to be properly disposed. Otter Tail Power Company considers this increase negligible compared to the existing amount flyash being properly disposed.

The selective non-catalytic reduction and the selective catalytic reduction will generate a small amount of unreacted ammonia or urea to be emitted. Even though ammonia and urea are not considered regulated air pollutants, these emissions are involved in the formation of ammonium sulfates and ammonium nitrates, which contribute to the amount of visibility impairment.

In conducting its cost analysis, Otter Tail Power Company used 30 years as the life expectancy averaging period for the control alternatives. Since the useful life of Otter Tail Power Company's Big Stone I facility is expected to be longer than 30 years, there is no difference between the control options based on useful life.

6.3.4 Visibility Impact Evaluations

In accordance with 40 CFR Part 51, Appendix Y, a source that has an impact equal to or greater than 1.0 deciviews is considered to "cause" a visibility impairment and that establishing a threshold for what is considered to "contribute" to a visibility impairment should not be any higher than 0.5 deciviews. DENR is proposing to define "contribute" to visibility impairment as a change in visibility impairment in a mandatory Class I federal area of 0.5 deciviews or more, based on a 24-hour average, above the average natural visibility baseline. A source exceeds the threshold when the 98th percentile (eighth highest value) of the modeling results, based on one year of the three years of meteorological data modeled, exceeds the 0.5 deciviews.

Otter Tail Power Company modeled its existing operations impact on seven Class I areas that are located in Michigan, Minnesota, North Dakota, and South Dakota. Table 6-12 identifies the potential impact based on the 98th percentile for the existing Big Stone I facility has while emitting approximately 18,000 tons of sulfur dioxide, 18,000 tons of nitrogen oxides, and 300 tons of particulate matter per year.

Table 6-12 – Potential Impact of Existing Big Stone I (98th Percentile)

Class I Area	2002 [1,2]	2006 [1,2]	2007 [1,2]
Boundary Waters	0.574 (0.6)	0.790 (0.8)	1.079 (1.1)
Voyageurs	0.623 (0.6)	0.574 (0.6)	0.724 (0.7)
Wind Cave	0.305 (0.3)	0.120 (0.1)	0.325 (0.3)
Theodore Roosevelt	0.215 (0.2)	0.459 (0.5)	0.322 (0.3)
Lostwood	0.232 (0.2)	0.385 (0.4)	0.409 (0.4)
Badlands	0.452 (0.5)	0.481 (0.5)	0.471 (0.5)
Isle Royale	0.629 (0.6)	0.506 (0.5)	0.665 (0.7)

[1] – The modeling was conducted using the meteorological data for calendar years 2002, 2006, and 2007; and

[2] – The results are represented in deciviews. Otter Tail Power Company identified the deciview valued identified in the model to three decimal places which is consistent with how WRAP reported the visibility impacts in Table 6-3. The value in parentheses represents the value that is used to compare to the proposed contribution threshold of 0.5.

Based on the modeling results, Otter Tail Power Company's Big Stone I facility contributes to visibility impairment at Boundary Waters, Voyageurs, Theodore Roosevelt, Badlands, and Isle Royale because they have a deciview impact of 0.5 or greater.

Otter Tail Power Company conducted visibility modeling for 10 different control option scenarios and each scenario for three calendar years worth of meteorological data. The 10 different control option scenarios simultaneously considered the emissions of nitrogen oxide, sulfur dioxide, and particulate matter. Table 6-13 identifies the emission rates used in the modeling for each different control option.

Table 6-13 – Emission Rates for Each Control Option

Option	Control Equipment	SO2 [11]	NOx [12]	PM10 [13]
#1	OFA and Dry FGD #1 [1]	841.4	3645.9	84.1
#2	OFA and Wet FGD #1 [2]	841.4	3645.9	84.1
#3	OFA and Dry FGD #2 [3]	504.8	3645.9	84.1
#4	OFA and Wet FGD #2 [4]	241.2	3645.9	84.1
#5	SOFA and Dry FGD #1 [5]	841.4	2804.5	84.1
#5a	SOFA and Dry FGD #2 [6]	504.8	2804.5	84.1
#5b	SOFA and Wet FGD #2 [7]	241.2	2804.5	84.1
#6	SNCR, SOFA, and Dry FGD #1 [8]	841.4	1963.2	84.1
#7	RRI, SNCR, SOFA, and Dry FGD #1 [9]	841.4	1121.8	84.1
#8	SCR, SOFA, and Dry FGD #1 [10]	841.4	560.9	84.1

[1] – OFA and Dry FGD #1 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[2] – OFA and Wet FGD #1 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[3] – OFA and Dry FGD #2 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[4] – OFA and Wet FGD #2 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[5] – SOFA and Dry FGD #1 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[6] – SOFA and Dry FGD #2 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[7] – SOFA and Wet FGD #2 refers to separated over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[8] – SNCR, SOFA, and Dry FGD #1 refers to selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[9] – RRI, SNCR, SOFA, and Dry FGD #1 refers to rich reagent injection, selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[10] – SCR, SOFA, and Dry FGD #1 refers to selective catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[11] – SO2 represents the sulfur dioxide emission rate in pounds per hour;
[12] – NOx represents the nitrogen oxide emission rate in pounds per hour; and

[13] – PM10 represents the particulate matter less than 10 microns emission rate in pounds per hour.

Table 6-14 provides the results of the modeling (98th percentile) using the different control options and emissions rates in Table 6-13. Again, Otter Tail Power Company identified the deciview valued identified in the model to three decimal places which is consistent with how WRAP reported the visibility impacts in Table 6-3. The value in parentheses represents the value that DENR used to compare to the proposed contribution threshold of 0.5.

Table 6-14 – Modeling Results for Each Control Option (98th Percentile – Deciviews)

Option	Control Equipment	Class I Area	2002	2006	2007
#1	OFA and Dry FGD #1 [1]	Boundary Waters	0.330 (0.3)	0.548 (0.5)	**0.657 (0.7)**
		Voyageurs	0.329 (0.3)	0.399 (0.4)	0.460 (0.5)
		Isle Royale	0.377 (0.4)	0.296 (0.3)	0.339 (0.3)
		Badlands	0.223 (0.2)	0.176 (0.2)	0.241 (0.2)
		Theodore Roosevelt	0.092 (0.1)	0.247 (0.2)	0.190 (0.2)
#2	OFA and Wet FGD #1 [2]	Boundary Waters	0.360 (0.4)	0.546 (0.5)	**0.667 (0.7)**
		Voyageurs	0.349 (0.3)	0.494 (0.5)	0.521 (0.5)
		Isle Royale	0.367 (0.4)	0.273 (0.3)	0.323 (0.3)
		Badlands	0.234 (0.2)	0.199 (0.2)	0.254 (0.3)
		Theodore Roosevelt	0.099 (0.1)	0.244 (0.2)	0.161 (0.2)
#3	OFA and Dry FGD #2 [3]	Boundary Waters	0.319 (0.3)	0.534 (0.5)	**0.620 (0.6)**
		Voyageurs	0.307 (0.3)	0.391 (0.4)	0.450 (0.5)
		Isle Royale	0.363 (0.4)	0.287 (0.3)	0.323 (0.3)
		Badlands	0.219 (0.2)	0.172 (0.2)	0.230 (0.2)
		Theodore Roosevelt	0.087 (0.1)	0.234 (0.2)	0.173 (0.2)
#4	OFA and Wet FGD #2 [4]	Boundary Waters	0.350 (0.4)	0.521 (0.5)	**0.611 (0.6)**
		Voyageurs	0.312 (0.3)	0.464 (0.5)	0.502 (0.5)
		Isle Royale	0.351 (0.4)	0.250 (0.3)	0.290 (0.3)
		Badlands	0.225 (0.2)	0.191 (0.2)	0.234 (0.2)
		Theodore Roosevelt	0.084 (0.1)	0.230 (0.2)	0.138 (0.1)
#5	SOFA and Dry FGD #1 [5]	Boundary Waters	0.264 (0.3)	0.433 (0.4)	0.524 (0.5)
		Voyageurs	0.263 (0.3)	0.314 (0.3)	0.364 (0.4)
		Isle Royale	0.298 (0.3)	0.235 (0.2)	0.272 (0.3)
		Badlands	0.169 (0.2)	0.137 (0.1)	0.191 (0.2)
		Theodore Roosevelt	0.076 (0.1)	0.199 (0.2)	0.156 (0.2)
#5a	SOFA and Dry FGD #2 [6]	Boundary Waters	0.250 (0.3)	0.419 (0.4)	0.493 (0.5)
		Voyageurs	0.249 (0.2)	0.306 (0.3)	0.354 (0.4)
		Isle Royale	0.285 (0.3)	0.226 (0.2)	0.256 (0.3)
		Badlands	0.165 (0.2)	0.133 (0.1)	0.180 (0.2)
		Theodore Roosevelt	0.069 (0.1)	0.186 (0.2)	0.141 (0.1)
#5b	SOFA and Wet FGD #2 [7]	Boundary Waters	0.274 (0.3	0.407 (0.4)	0.478 (0.5)
		Voyageurs	0.244 (0.2)	0.365 (0.4)	0.393 (0.4)
		Isle Royale	0.274 (0.3)	0.195 (0.2)	0.227 (0.2)
		Badlands	0.174 (0.2)	0.147 (0.1)	0.182 (0.2)

Option	Control Equipment	Class I Area	2002	2006	2007
		Theodore Roosevelt	0.066 (0.1)	0.180 (0.2)	0.108 (0.1)
#6	**SNCR, SOFA, and Dry FGD #1** [8]	**Boundary Waters**	**0.200 (0.2)**	**0.318 (0.3)**	**0.388 (0.4)**
		Voyageurs	**0.196 (0.2)**	**0.228 (0.2)**	**0.267 (0.3)**
		Isle Royale	**0.221 (0.2)**	**0.174 (0.2)**	**0.199 (0.2)**
		Badlands	**0.120 (0.1)**	**0.098 (0.1)**	**0.143 (0.1)**
		Theodore Roosevelt	**0.063 (0.1)**	**0.150 (0.2)**	**0.121 (0.1)**
#7	**RRI, SNCR, SOFA, and Dry FGD #1** [9]	**Boundary Waters**	**0.137 (0.1)**	**0.202 (0.2)**	**0.256 (0.3)**
		Voyageurs	**0.130 (0.1)**	**0.157 (0.2)**	**0.176 (0.2)**
		Isle Royale	**0.142 (0.1)**	**0.115 (0.1)**	**0.134 (0.1)**
		Badlands	**0.090 (0.1)**	**0.066 (0.1)**	**0.099 (0.1)**
		Theodore Roosevelt	**0.050 (0.1)**	**0.101 (0.1)**	**0.080 (0.1)**
#8	**SCR, SOFA, and Dry FGD #1** [10]	**Boundary Waters**	**0.097 (0.1)**	**0.136 (0.1)**	**0.170 (0.2)**
		Voyageurs	**0.086 (0.1)**	**0.107 (0.1)**	**0.123 (0.1)**
		Isle Royale	**0.092 (0.1)**	**0.077 (0.1)**	**0.098 (0.1)**
		Badlands	**0.079 (0.1)**	**0.060 (0.1)**	**0.070 (0.1)**
		Theodore Roosevelt	**0.036 (0.0)**	**0.070 (0.1)**	**0.064 (0.1)**

[1] – OFA and Dry FGD #1 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[2]- OFA and Wet FGD #1 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[3] - OFA and Dry FGD #2 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[4] - OFA and Wet FGD #2 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[5] – SOFA and Dry FGD #1 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[6] – SOFA and Dry FGD #2 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[7] – SOFA and Wet FGD #2 refers to separated over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[8] – SNCR, SOFA, and Dry FGD #1 refers to selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[9] - RRI, SNCR, SOFA, and Dry FGD #1 refers to rich reagent injection, selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units; and
[10] - SCR, SOFA, and Dry FGD #1 refers to selective catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units.

Based on the modeling results in Table 6-14, Otter Tail Power Company would have to use Option #6, #7, or #8 to not reasonably contribute to visibility impairment in the Boundary Waters, Voyageurs, Isle Royale, Badlands, and Theodore Roosevelt National Parks.

Otter Tail Power Company did not provide a cost per deciview reduction for each of the proposed control options. DENR calculated a cost per deciview reduction by summing the annualized cost of each of the control alternatives associated with the control options and dividing by the visibility reduction identified by the modeling from the baseline condition. Table 6-15 provides a cost per deciview comparison.

Table 6-15 – Cost per Deciview Comparison ($/deciview)

Option	Control Equipment	Class I Area	2002	2006	2007
#1	OFA and Dry FGD #1 [1]	Boundary Waters	$ 96,188,525	$ 96,983,471	$ 55,616,114
		Voyageurs	$ 79,829,932	$ 134,114,286	$ 88,901,515
		Isle Royale	$ 93,134,921	$ 111,761,905	$ 71,993,865
		Badlands	$ 102,489,083	$ 79,950,820	$ 102,043,478
		Theodore Roosevelt	$ 190,813,008	$ 110,707,547	$ 177,803,030
		Cumulative	**$ 15,998,637**	**$ 16,108,442**	**$ 13,542,989**
#2	OFA and Wet FGD #1 [2]	Boundary Waters	$ 135,700,935	$ 119,016,393	$ 70,485,437
		Voyageurs	$ 105,985,401	$ 363,000,000	$ 143,054,187
		Isle Royale	$ 110,839,695	$ 124,635,193	$ 84,912,281
		Badlands	$ 133,211,009	$ 102,978,723	$ 133,824,885
		Theodore Roosevelt	$ 250,344,828	$ 135,069,767	$ 180,372,671
		Cumulative	**$ 20,625,000**	**$ 21,337,252**	**$ 17,224,199**
#3	OFA and Dry FGD #2 [3]	Boundary Waters	$ 92,980,392	$ 92,617,188	$ 51,655,773
		Voyageurs	$ 75,031,646	$ 129,562,842	$ 86,532,847
		Isle Royale	$ 89,135,338	$ 108,264,840	$ 69,327,485
		Badlands	$ 101,759,657	$ 76,731,392	$ 159,127,517
		Theodore Roosevelt	$ 185,234,375	$ 105,377,778	$ 98,381,743
		Cumulative	**$ 15,466,406**	**$ 15,588,429**	**$ 12,795,467**
#4	OFA and Wet FGD #2 [4]	Boundary Waters	$ 130,312,500	$ 108,513,011	$ 62,371,795
		Voyageurs	$ 93,858,521	$ 265,363,636	$ 131,486,486
		Isle Royale	$ 105,000,000	$ 114,023,438	$ 77,840,000
		Badlands	$ 128,590,308	$ 100,655,172	$ 123,164,557
		Theodore Roosevelt	$ 222,824,427	$ 127,467,249	$ 158,641,304
		Cumulative	**$ 19,140,984**	**$ 19,590,604**	**$ 15,617,978**
#5	SOFA and Dry FGD #1 [5]	Boundary Waters	$ 77,354,839	$ 67,170,868	$ 43,207,207
		Voyageurs	$ 66,611,111	$ 92,230,769	$ 66,611,111
		Isle Royale	$ 72,447,130	$ 88,487,085	$ 61,017,812
		Badlands	$ 84,734,392	$ 69,709,302	$ 85,642,857
		Theodore Roosevelt	$ 172,517,986	$ 92,230,769	$ 144,457,831
		Cumulative	**$ 13,411,633**	**$ 13,018,458**	**$ 11,045,601**
#5a	SOFA and Dry FGD #2 [6]	Boundary Waters	$ 74,753,086	$ 65,283,019	$ 41,331,058
		Voyageurs	$ 64,759,358	$ 90,373,134	$ 65,459,459
		Isle Royale	$ 70,406,977	$ 86,500,000	$ 59,217,604
		Badlands	$ 84,390,244	$ 69,597,701	$ 83,230,241
		Theodore Roosevelt	$ 165,890,411	$ 88,717,949	$ 133,812,155

Option	Control Equipment	Class I Area	2002	2006	2007
		Cumulative	**$ 13,070,696**	**$ 12,727,273**	**$ 10,544,188**
#5b	SOFA and Wet FGD #2 [7]	Boundary Waters	$ 99,000,000	$ 77,545,692	$ 49,417,637
		Voyageurs	$ 78,364,116	$ 142,105,263	$ 89,728,097
		Isle Royale	$ 83,661,972	$ 95,498,392	$ 67,808,219
		Badlands	$ 106,834,532	$ 88,922,156	$ 102,768,166
		Theodore Roosevelt	$ 199,328,589	$ 106,451,613	$ 138,785,047
		Cumulative	**$ 16,019,417**	**$ 15,730,932**	**$ 12,724,936**
#6	SNCR, SOFA, and Dry FGD #1 [8]	Boundary Waters	$ 73,048,128	$ 57,881,356	$ 39,536,903
		Voyageurs	$ 63,981,265	$ 78,959,538	$ 59,781,182
		Isle Royale	$ 66,960,784	$ 82,289,157	$ 58,626,609
		Badlands	$ 82,289,157	$ 71,331,593	$ 83,292,683
		Theodore Roosevelt	$ 179,736,842	$ 88,414,239	$ 135,920,398
		Cumulative	**$ 13,115,699**	**$ 12,262,118**	**$ 10,368,121**
#7	RRI, SNCR, SOFA, and Dry FGD #1 [9]	Boundary Waters	$ 79,450,801	$ 59,047,619	$ 42,187,120
		Voyageurs	$ 70,425,963	$ 83,261,391	$ 63,357,664
		Isle Royale	$ 71,293,634	$ 88,797,954	$ 65,386,064
		Badlands	$ 95,911,602	$ 83,662,651	$ 93,333,333
		Theodore Roosevelt	$ 210,424,242	$ 96,983,240	$ 143,471,074
		Cumulative	**$ 14,711,864**	**$ 13,467,804**	**$ 11,280,052**
#8	SCR, SOFA, and Dry FGD #1 [10]	Boundary Waters	$ 76,603,774	$ 55,871,560	$ 40,198,020
		Voyageurs	$ 68,044,693	$ 78,244,111	$ 60,798,669
		Isle Royale	$ 68,044,693	$ 85,174,825	$ 64,444,444
		Badlands	$ 97,962,466	$ 86,793,349	$ 91,122,195
		Theodore Roosevelt	$ 204,134,078	$ 93,933,162	$ 141,627,907
		Cumulative	**$ 14,329,412**	**$ 13,101,470**	**$ 10,900,955**

[1] – OFA and Dry FGD #1 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[2]- OFA and Wet FGD #1 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[3] - OFA and Dry FGD #2 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[4] - OFA and Wet FGD #2 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[5] – SOFA and Dry FGD #1 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[6] – SOFA and Dry FGD #2 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[7] – SOFA and Wet FGD #2 refers to separated over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[8] – SNCR, SOFA, and Dry FGD #1 refers to selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;

[9] - RRI, SNCR, SOFA, and Dry FGD #1 refers to rich reagent injection, selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units; and
[10] - SCR, SOFA, and Dry FGD #1 refers to selective catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units.

Based on the cost per deciview reduction numbers in Table 6-15, the most cost effective controls options are #5A, #6 and #8. The cost effective control costs are generally within 10 percent of each other.

6.3.5 BART Emissions Limits for Big Stone I

EPA identifies in 40 CFR Part 51, Appendix Y that in determining the "best" available retrofit technology, the state has discretion to determine the order in which the state should evaluate control options for BART. The state should provide a justification for adopting the technology that is selected as the ''best'' level of control, including an explanation of the Clean Air Act factors that led the state to choose that option over other control levels.

To complete the BART process, the state should establish enforceable emission limits that reflect the BART requirements and require compliance within a given period of time. In particular, the state should establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source. In addition, the state should require compliance with the BART emission limitations no later than five years after EPA approves South Dakota's State Implementation Plan for regional haze. If technological or economic limitations in the application of a measurement methodology to a particular emission unit make a conventional emissions limit infeasible, the state may instead prescribe a design, equipment, work practice, operation standard, or combination of these types of standards.

6.3.5.1 Particulate Matter BART Recommendation

Otter Tail Power Company already installed and is operating a baghouse, which is the top particulate control technology. Therefore, there is no additional compliance cost, energy impacts, etc. that Otter Tail Power Company would have to endure. As such, DENR considers the continual use of the baghouse as BART for particulate matter.

Otter Tail Power Company proposes an emission limit of 84.1 pounds per hour which they based on an emission rate of 0.015 pounds per million Btu and a maximum fuel heat input of 5,609 million Btus per hour. Otter Tail Power Company proposes to comply with the pounds per hour limit using a 30-day rolling average. Each day, Otter Tail Power Company will multiply the emission rate, in pounds per million Btus as determined by the most recent annual performance test, by the heat input to the boiler, as determined by a continuous emission monitoring system, and dividing by the number of hours the boiler operated that day.

In the December 11, 2006, application, Otter Tail Power Company proposed to replace the advanced hybrid particulate collector control system with the current day baghouse. In that application, Otter Tail Power Company noted that the baghouse would have a maximum filterable particulate matter emission rate of 0.012 pounds per million Btu of fuel heat input. The emission rate equates to 67.3 pounds per hour at 5,609 million Btus per hour heat input In May 2009, Otter Tail Power Company conducted a performance test on the baghouse. The test results noted an average filterable particulate matter emission rate of 0.011 pounds per million Btus and 57.6 pounds per hour.

DENR considers the emission limit representing BART as 67.3 pounds per hour. The hourly emission limit includes periods of startup and shutdown. DENR is also establishing a BART emission limit of 0.012 pounds per million Btus, which does not include periods of startup and shutdown. Compliance with both emission limits shall be based on an annual stack performance test using the average of three 1-hour test runs.

6.3.5.2 Sulfur Dioxide BART Recommendation

Otter Tail Power Company is proposing the second ranked control option (semi-dry flue gas desulfurization system) to control sulfur dioxide emissions. Since control options #6, #7, and #8, which were the only three options that reduced the visibility less than the contribution level of 0.5 deciviews, did not include the top ranked sulfur dioxide control alternative an analysis of the visibility impacts of the other control alternatives was considered. Even though the top ranked control option (wet flue gas desulfurization system) reduces the sulfur dioxide emissions more than the second ranked control option, neither of the two control options is considered a better control option when considering the visibility impacts. For example, Table 6-16 displays the comparison of the visibility impacts for control option #3 to control option #4 and control option #5a to control option #5b. These options were chosen because the emission rates for nitrogen oxide and particulate matter were constant, while the sulfur dioxide emissions varied as noted by the two different control alternatives.

Table 6-16 – Visibility Comparison between Wet and Dry Scrubbers

	Control Option	Class I Area	2002	2006	2007
#3	OFA and Dry FGD #2 [1]	Boundary Waters	0.319	0.534	0.620
		Voyageurs	0.307	0.391	0.450
		Isle Royale	0.363	0.287	0.323
		Badlands	0.219	0.172	0.230
		Theodore Roosevelt	0.087	0.234	0.173
#4	OFA and Wet FGD #2 [2]	Boundary Waters	0.350	0.521	0.611
		Voyageurs	0.312	0.464	0.502
		Isle Royale	0.351	0.250	0.290
		Badlands	0.225	0.191	0.234
		Theodore Roosevelt	0.084	0.230	0.138
	Comparison Review	Boundary Waters	↑	↓	↓
		Voyageurs	↑	↑	↑
		Isle Royale	↓	↓	↓
		Badlands	↑	↑	↑
		Theodore Roosevelt	↓	↓	↓

	Control Option	Class I Area	2002	2006	2007
#5a	SOFA and Dry FGD #2 [3]	Boundary Waters	0.250	0.419	0.493
		Voyageurs	0.249	0.306	0.354
		Isle Royale	0.285	0.226	0.256
		Badlands	0.165	0.133	0.180
		Theodore Roosevelt	0.069	0.186	0.141
#5b	SOFA and Wet FGD #2 [4]	Boundary Waters	0.274	0.407	0.478
		Voyageurs	0.244	0.365	0.393
		Isle Royale	0.274	0.195	0.227
		Badlands	0.174	0.147	0.182
		Theodore Roosevelt	0.066	0.180	0.108
	Comparison Review	Boundary Waters	↑	↓	↓
		Voyageurs	↓	↑	↑
		Isle Royale	↓	↓	↓
		Badlands	↑	↑	↑
		Theodore Roosevelt	↓	↓	↓

[1] - OFA and Dry FGD #2 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[2] - OFA and Wet FGD #2 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[3] – SOFA and Dry FGD #2 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units; and
[4] – SOFA and Wet FGD #2 refers to separated over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units.

As noted in the table, approximately 40 percent of the modeling, the top ranked control option generated a higher visibility impact than the second ranked control option. Whereas, approximately 60 percent of the modeling, the second ranked control option generated a higher visibility impact than the top ranked control option. Therefore, based on the visibility modeling there is no discernable difference between these two control options. As such, DENR considers that the semi-dry flue gas desulfurization system is considered BART.

Otter Tail Power Company proposes an emission limit of 505 pounds per hour based upon a 30-day rolling average, which is based on the emission rate of 0.09 pounds per million Btu of fuel heat input at 5,609 million Btus per hour heat input.

The presumptive emission limit established by EPA for scrubber systems is 0.15 pounds per million Btus of fuel heat input. The limit proposed by Otter Tail Power Company is more stringent than the presumptive limit identified by EPA. DENR considers the emission limit representing BART should be 505 pounds per hour, which would include periods of startup and shutdown and 0.09 pounds per million Btus, which would not include startup and shutdown. Compliance with these emission limits shall be based on the continuous emission monitoring system and on a 30-day rolling average.

6.3.5.3 Nitrogen Oxide BART Recommendation

Otter Tail Power Company is proposing the fourth ranked control option (separated over-fire air) to control nitrogen oxide emissions. In reviewing the higher ranked control options, each option reduces the amount of nitrogen oxide emissions and the visibility impacts more than the fourth ranked control option (separated over-fire air). However, each of these higher ranking control options comes with a higher financial cost.

In establishing the nitrogen oxide presumptive BART requirements, EPA identified that $1,500 per ton of nitrogen oxide removed was considered cost effective. (Federal Register Volume 70 Number 128 on pages 39134 and 39135). EPA considers this threshold cost effective for a coal fired unit greater than 200 megawatts existing at a facility with a combined capacity greater than 750 megawatts.

Otter Tail Power Company's Big Stone I facility does not have a capacity greater than 750 megawatts and is not applicable to the established nitrogen oxide presumptive BART requirements. However, Otter Tail Power Company's Big Stone I's coal fired unit is greater than the 200 megawatt. As noted in Table 6-10, the cost of the control options on a $ per ton basis are all less than $900 per ton. As such DENR considers all the identified control options as cost effective on a $ per ton basis.

As noted in Table 6-15, the cost on a $ per deciview basis indicates that control options #5a, #6 and #8 are the most cost effective. Options #5a, #6 and #8 consider the operation of separated over-fire air, selective non catalytic reduction and selective catalytic reduction. It should be noted that the $ per deciview includes the cost for both sulfur dioxide and nitrogen oxide.

As noted in Table 6-14, control options #6, #7, #8, were the only options that resulted in modeling less than 0.5 deciviews of visibility impairment. Again, it should be noted the modeling results includes the emissions of particulate matter, sulfur dioxide, and nitrogen oxide.

None of the nitrogen oxide control alternatives have identified energy, non-air environmental, or have issues with the current life expectancy of the Big Stone I coal fire unit to preclude the use of any of the control options. As such DENR considers all the identified control options as being acceptable options based on impacts to energy, non-air environmental and life expectancy.

Based on the visibility modeling, the first ranked control option (selective catalytic reduction) reduces the visibility more than any other control option. The selective catalytic reduction system also reduces the visibility an additional 34 percent over the second ranked control option and an additional 65 percent over the fourth ranked control option. The selective catalytic reduction is also considered cost effective on a $ per ton basis, is represented as part of the control option #8 that is one of the most cost effective options on a $ per deciview reduction basis and one of the options that modeling demonstrates less than 0.5 deciviews of visibility impairment. DENR considers selective catalytic reduction and separate over-fire air system as BART.

The presumptive emission limit established by EPA for a selective catalytic reduction system installed on a cyclone coal fired unit is 0.10 pounds per million Btus of fuel heat input (Federal Register Volume 70 Number 128 on page 39172). DENR considers the emission limit representing BART should be 561 pounds per hour, which would include periods of startup and shutdown and 0.10 pounds per million Btus, which would not include startup and shutdown periods. Compliance with the emission limits shall be based on the continuous emission monitoring system and on a 30-day rolling average.

6.4 BART Requirements

Otter Tail Power Company's Big Stone I reasonably contributes to visibility impairment at Class I areas and is considered a BART-eligible source subject to BART. Therefore, DENR is adopting BART requirements in its Administrative Rules of South Dakota under Chapter 74:36:21 – Regional Haze Program.

These requirements will be part of South Dakota's Regional Haze State Implementation Plan and will be enforceable because they will establish emission limits representing BART; in accordance with 40 CFR § 51.308(e)(1)(v), the BART control equipment will be required to be properly operated and maintained; and testing, monitoring, recordkeeping, and reporting requirements will be established to ensure compliance with BART. One method of determining if control equipment is being properly operated and maintained is through monitoring the emissions from the unit. In Otter Tail Power Company's case, continuous emission monitoring sulfur dioxide and nitrogen oxide is already required in their existing permit. The minimum requirements for the operation, maintenance, and monitoring requirements will be established in ARSD 74:36:21:07. In accordance with 40 CFR § 51.308(e)(1)(iv), DENR will require BART to be installed and operating as expeditiously as practicable, but no later than 5 years from EPA's approval of South Dakota's Regional Haze Program. The deadline for installing BART will be established in ARSD 74:36:21:06.

In accordance with 40 CFR § 51.308(e)(5), once the requirements of BART are achieved, Otter Tail Power Company will be subject to the requirements of South Dakota's State Implementation Plan in the same manner as other sources.

7.0 Reasonable Progress

In accordance with 40 CFR § 51.308(d)(1), for each mandatory Class I area located within the state, the state must establish goals, expressed in deciviews, that provide reasonable progress towards achieving natural visibility conditions by 2064. The reasonable progress goals must provide improvement in visibility for the 20% most impaired days over the period of the implementation plan and ensure no degradation in visibility for the 20% least impaired days over the same period. In accordance with 40 CFR § 51.308(d)(1)(v), the reasonable progress goals established by the state are not directly enforceable but will be considered in the evaluation of the adequacy of the measures a state would implement to achieve natural conditions by 2064. In accordance with 40 CFR § 51.308(d)(1)(vi), the state may not adopt a reasonable progress goal

ATTACHMENT 2

ASSESSMENT OF ANTICIPATED FEDERAL AND STATE ENVIRONMENTAL REGULATIONS

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ASSESSMENT OF ANTICIPATED FEDERAL AND STATE ENVIRONMENTAL REGULATIONS

This Attachment 2 to the Application summarizes and assesses all anticipated state and federal environmental regulations related to production of electricity from the Big Stone Plant. This Attachment addresses anticipated air quality regulations in Sections I to III, then addresses anticipated coal waste regulations in Section IV, and ends by assessing anticipated water regulations in Section V.

I. Criteria Air Pollutants

The "criteria" air pollutants are: nitrogen oxides ("NO_X"), sulfur dioxide ("SO_2"), particulate matter ("PM"), ozone, carbon monoxide and lead. These are the six pollutants for which EPA has adopted National Ambient Air Quality Standards, but their emissions are also regulated under other Clean Air Act ("CAA") programs when they are a precursor to other types of air pollution. NO_X, for example, is regulated because it is a precursor to fine particle formation, ozone formation, acid deposition and regional haze. Similarly, SO_2 is a precursor to fine particle formation, acid deposition and regional haze. Particulate matter is a precursor to regional haze. This section describes the effect of anticipated regulations to limit criteria pollutant emissions from power plants.

A. National Ambient Air Quality Standards

The Clean Air Act provides that National Ambient Air Quality Standards ("NAAQS") be evaluated every five years, and based on the most recent scientific information available, be revised if necessary to protect public health and/or the environment.[1] The EPA has recently revised the NAAQS for several pollutants and is expected to make determinations setting new ozone and particulate standards by the end of 2011.

Big Stone is located in an area that attains all NAAQS, and is not located in or near any areas expected to fail to attain NAAQS. Furthermore, the Big Stone AQCS will reduce ambient concentrations of SO_2, NO_X, and ozone (to the extent that NO_x is a chemical precursor of ozone formation). SO_2 and NO_X also contribute to the secondary formation of fine particulate, or particulate matter less than 2.5 microns ("$PM_{2.5}$"), which is also regulated under the NAAQS program.

In general, compliance with NAAQS is achieved through development of State Implementation Plans ("SIPs") that limit emissions from sources located in the area designated non-attainment.[2] To help states attain the NAAQS in local areas, the EPA evaluates whether certain regional or nationally applicable emission limitations should be put into place in order to assist the states in

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1 42 U.S.C. § 7409 (CAA § 109).

2 42 U.S.C. § 7410 (CAA § 110).

attaining the NAAQS, or states may petition EPA to impose reductions in upwind states.[3] In the case of ozone and particle pollution, EPA has determined that it should adopt regional strategies in the Eastern United States to reduce precursor emissions from power plants that contribute to downwind nonattainment. In the electric power industry, attempts to assist with attainment of the NAAQS for ozone and particulate matter from regional sources have been made through EPA's proposed Transport Rule and its predecessor, the Clean Air Interstate Rule ("CAIR").

Based on a conclusion that SO_2 and NO_X are the chief emissions contributing to interstate transport of $PM_{2.5}$, and that NO_X emissions are the chief contributor to ozone non-attainment, the EPA adopted the final CAIR rule in May 2005.[4] In the final CAIR rule, 25 states and the District of Columbia were found to contribute to $PM_{2.5}$ NAAQS non-attainment in downwind states. Twenty-five states and the District of Columbia were found to contribute to downwind eight-hour ozone NAAQS non-attainment. Based on this impact, the EPA proposed to cap SO_2 and NO_X emissions in the designated states. The initial program design implemented significant emission reductions through caps and then proposed to allow emission trading in the CAIR control region among sources targeted for emission reductions. On July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated and remanded CAIR and the CAIR Federal Implementation Plan in its entirety.[5]

On August 2, 2010, the EPA published a proposed rule to replace CAIR, which EPA referred to as the "Transport Rule."[6] The Transport Rule would seek to reduce SO_2 by 71% and NO_X by 52% from 2005 levels by 2014. EPA expects to issue its final Transport Rule in 2012. In the proposed Transport Rule, 24 states and the District of Columbia were found to contribute to $PM_{2.5}$ NAAQS non-attainment in downwind states. Twenty-four states and the District of Columbia were found to contribute to downwind eight-hour ozone NAAQS non-attainment. The Big Stone Plant is located in South Dakota. South Dakota was not subject to CAIR and is not proposed to be subject to Transport Rule requirements.

EPA plans to evaluate the need for further emission reductions in the Transport Rule, based upon revisions to the NAAQS for ozone and particulate that EPA may implement in the future. It is not expected that South Dakota would be included in these revisions, but the Co-owners note that under the BART determination on Big Stone, Big Stone plans to install Best Available Retrofit Technology for control of both SO_2 and NO_X. As a result, even if South Dakota were to be

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3 42 U.S.C. § 7410(a)(2)(D)(i)(I) (CAA § 110(a)(2)(D)(i)(I)) provides that SIPs must contain adequate provisions to prohibit emissions from sources in the state that will "contribute significantly to nonattainment in, or interfere with maintenance by, any other State" of compliance with NAAQS. The CAA also contains a procedure for a state to petition EPA for a finding of contribution from sources located in other states. 42 U.S.C. § 7426 (CAA § 126).

4 70 Fed. Reg. 25162, 25165 (May 12, 2005), Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule, Final Rule).

5 *North Carolina v. E.P.A.*, 531 F.3d 896, 901 (D.C.Cir. 2008). After initially vacating the CAIR rule, the court decided to allow CAIR to go into effect pending revisions to the program to address the numerous flaws the court found in the rule.

6 75 Fed. Reg. 45210, 45215 (Aug. 2, 2010), Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, Proposed Rule.

included in future iterations of the Transport Rule control program, the Co-owners would not anticipate needing to install greater controls than are currently proposed in the Big Stone AQCS Project.[7]

B. Acid Deposition

Under Title IV of the 1990 amendments to the Clean Air Act, emissions of SO_2 and NO_X from the electric utility industry have been reduced substantially. To control SO_2 emissions, Title IV limits national total SO_2 emissions to 8.9 million tons per year and utilizes an emission allowance program where allowances to emit SO_2 are distributed to power plants.[8] An allowance is an authorization to emit one ton of SO_2 and is tradable.[9] As a result, facilities have reduced SO_2 where it is most cost-effective to do so, and have purchased emission allowances to cover SO_2 emissions where the cost of control at a particular facility is high. The Co-owners currently receive a sufficient number of SO_2 emission allowances to meet the requirements of Title IV at the Big Stone Plant and has not purchased allowances to meet the Title IV requirements.

In addition, Title IV requires that national NO_X emission reduction goals be achieved through mandatory emission standards that limit emissions at individual power plants. Big Stone meets the current NO_X emission limitations that apply to it under Title IV of the Clean Air Act.

The Co-owners do not anticipate any changes to the Title IV Acid Deposition Program under the Clean Air Act.

C. Regional Haze Program

The main feature of the Regional Haze Program that relates to electric power plants constructed between 1962 and 1977 is the requirement to install BART.[10] That requirement will be met by installation and operation of the Big Stone AQCS that is proposed in this proceeding. In addition, the Co-owners note that the state agencies are required to periodically review their visibility SIPs every five years, evaluate progress in meeting visibility improvement goals, and determine whether their SIPs need to be revised to require additional emission reductions.[11]

Because the Big Stone AQCS Project would install the top control technologies for the pollutants affecting visibility, the Co-owners do not anticipate further controls being required on Big Stone

7 There was some interest in Congress in legislatively adopting the CAIR program after the court reversed the rule. In the last Congress, Senators Carper and Alexander introduced a bill designed to accomplish this, which was not enacted.

8 42 U.S.C. § 7651b(a)(1) (CAA § 403(a)(1)).

9 42 U.S. C. §§ 7651a(3) (CAA § 402(3)) and 7651b(f) (CAA § 403(f)).

10 “Regional haze” is caused when sunlight encounters tiny pollution particles in the air. Some light is absorbed and other light is scattered before it reaches an observer, reducing the clarity and color of what the observer sees, causing impairment of visibility.

11 40 C.F.R. § 51.308 (g) & (h).

as a result of future five-year reviews by South Dakota of its Regional Haze SIP. While there is potential for change (for example, if control technologies are developed that are more efficient than those currently available), the Co-owners note that the control technologies required for the Big Stone AQCS provide very high reductions in PM, NO_X and SO_2, meaning that further improvements in control technology could reduce pollutants only marginally more than the levels that will be achieved by the Big Stone AQCS.

II. Hazardous Air Pollutants

The 1990 Amendments to the CAA required EPA to study the effects of emissions of listed hazardous air pollutants by electric steam generating plants.[12] The EPA completed required studies and submitted reports to Congress, and determined that it would regulate mercury emissions from electric generating units under the hazardous air pollutant requirements of the CAA.[13] EPA then published final rules that reversed this determination and set forth a cap and trade program for mercury emissions under the New Source Performance Standard provisions of the CAA.[14] EPA's mercury rule was reversed by the United States Court of Appeals for the D.C. Circuit on February 8, 2008.[15] The Court ruled that EPA had not properly followed the procedures set forth in Section 112 of the CAA to remove the requirement to regulate mercury emissions from electric generating units under the hazardous air pollutant provisions of the Act.

EPA has decided to commence a rulemaking to control mercury and other hazardous air pollutant emissions from power plants under the Maximum Achievable Control Technology ("MACT") provision of Section 112. This action will apply standards to existing electric generating units, as well as establish standards for any new units that would be constructed. EPA has issued information collection requests to assist it in developing this standard, and has agreed to a settlement of litigation about the timing of issuance of the Utility MACT standard which would require that the standard be proposed in early 2011 and adopted in November 2011. The EPA Administrator signed the proposed rule on March 16, 2011, and EPA published it in the May 3, 2011 *Federal Register*. Subject to limited exceptions, once a MACT standard is effective, sources have three years to achieve compliance.

Coincident with the Big Stone AQCS Project, the Co-owners plan to install equipment for mercury control. The Co-owners anticipate that compliance with the Utility MACT standard will require installation of carbon injection equipment, which will have an estimated capital cost of $5 million.[16] While the capital requirements for the carbon injection equipment are small in

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[12] 42. U.S.C. § 7412(n)(1) (CAA § 112(n)(1).

[13] 65 Fed. Reg. 79825 (Dec. 20, 2000), Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units.

[14] 70 Fed. Reg. 15994 (March 25, 2005), Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units From the Section 112(c) List, and 70 Fed. Reg. 28606 (May 18, 2005), Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units.

[15] *New Jersey v. E.P.A.*, 517 F.3d 574 (D.C.Cir. 2008).

[16] Attachment 6, ACI Estimate.

relation to the capital requirements for other types of pollution control equipment in the AQCS Project, the operating costs to purchase and use the injected material that collects the mercury are comparatively higher in relation to other types of control equipment. As a result, the Co-owners expect the cost of mercury control once the MACT standard is adopted to be approximately $2 million per year.[17] The mercury control technology is expected to use specialized lances to inject powdered activated carbon into the flue gas ductwork prior to the spray dryer. The technology is designed to target 90% mercury removal.

The Co-owners additionally note that the Utility MACT standard may deal with other hazardous air pollutants besides mercury, including metals, acid gases and organic hazardous air pollutants. The Co-owners anticipate that the Big Stone AQCS will be able to capture portions of the other hazardous air pollutants subject to the MACT standard due to the effectiveness of the designated control technology.[18] Therefore, the Co-owners anticipate that compliance with the upcoming Utility MACT standard will be achieved by the Big Stone AQCS with the addition of mercury control equipment.

III. Greenhouse Gas Regulation

A. Greenhouse Gas Regulation Under the Clean Air Act

1. Background

In April 2007, the U.S. Supreme Court issued a decision that determined that the EPA has authority to regulate carbon dioxide (“CO_2”) and other greenhouse gases (“GHGs”) as air pollutants under the CAA. The Supreme Court remanded the case to the EPA to conduct a rulemaking to decide whether GHGs may reasonably be anticipated to endanger public health or welfare, and if so, whether GHGs cause or contribute to climate change.[19] While this case addressed a provision of the CAA related to emissions for motor vehicles, other provisions of the CAA apply to stationary sources such as electric generating units.

The first step in the EPA rulemaking process was the publication of an endangerment finding in the Federal Register on December 15, 2009.[20] The EPA found that CO_2 and five other GHGs – methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride – threatened public health and the environment. EPA then adopted GHG standards for new light-duty vehicles as part of a joint rulemaking with the Department of Transportation.[21] These

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[17] Attachment 7.

[18] The semi-dry FGD with baghouse is expected to provide the most effective control of acid gases for plants like Big Stone. Similarly, non-mercury trace metals are effectively captured in particulate control systems like baghouses.

[19] *Massachusetts v. Environmental Protection Agency*, 549 U.S. 497 (2007).

[20] 74 Fed. Reg. 66496 (Dec. 15, 2009), Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act.

[21] 75 Fed. Reg. 25324 (May 7, 2010), Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards (Light Duty Vehicle Rule, Final Rule).

standards apply to motor vehicles as of January 2011, which makes GHGs "subject to regulation" under the CAA. Although applicable only to motor vehicles, the standard regulates GHG emissions for the first time under the CAA, and GHG emissions are therefore included in the pollutants subject to the requirements of the New Source Review program of the CAA.

2. New Source Review

Under the New Source Review Program, the Prevention of Significant Deterioration ("PSD") program applies to areas of the country that attain the NAAQS, such as the area in which the Big Stone Plant is located. PSD review requires persons constructing new major air pollution sources or implementing significant modifications to existing air pollution sources that constitute a significant net emissions increase to obtain a permit prior to such construction or modification.[22] In order to obtain a PSD permit, the owner or operator of an affected facility must undergo a review which requires the identification and implementation of best-available control technology ("BACT") for the regulated air pollutants for which there is a significant net emissions increase, and an analysis of the ambient air quality impacts of the facility.

On May 13, 2010, EPA issued a final "tailoring rule" that phases in application of this program to GHG emission sources, including power plants.[23] This program applies to existing sources such as Big Stone if there is a physical change or change in the method of operation of the facility that results in a significant net emissions increase. As a result, PSD does not apply on a set timeline as is the case with other regulatory programs, but is triggered depending on what activities take place at a major source.

The EPA decided to phase in the PSD requirements for GHGs in two steps. Beginning on January 2, 2011, GHG control analysis will be conducted in PSD permit proceedings only if changes at a facility trigger PSD for criteria pollutants and if the proposed change increases GHGs by over 75,000 tons per year of "CO_2e," a measure that converts emissions of each GHG into its carbon dioxide equivalent.[24] Until July of 2011, the threshold applies only to facilities currently subject to PSD or Title V permitting. However, as of July 2011, sources emitting more than 100,000 tons per year of CO_2e are considered "major sources" subject to PSD requirements if they propose to make modifications resulting in a net GHG emissions increase of 75,000 tons per year or more of CO_2e.[25]

The gross generating capacity of the Big Stone Plant will not increase as part of the AQCS Project. Furthermore, it is necessary as part of this project to reduce the temperature of the flue gas exiting the boiler by improving the boiler efficiency, so that the flue gas will be within the temperature range required for operation of the SCR control equipment. The Plant will also need to provide additional electricity to the new AQCS, i.e. increased station service, as reflected by the increase in the net plant heat rate (Btu/kWh net). The additional electricity requires

22 40 C.F.R. § 52.21, Prevention of Significant Deterioration of Air Quality.

23 75 Fed. Reg. 31514 (June 3, 2010), PSD Greenhouse Gas Tailoring Rule.

24 *Id.* at 31523.

25 *Id.*

combustion of a small amount of additional coal. However, the increase in GHG emissions is projected to be less than 75,000 tons per year. Consequently, GHG emissions are not projected to trigger the need for a PSD permit as a result of the AQCS Project, and the PSD program requirements would not apply as a result of the Project.

3. New Source Performance Standards

EPA has announced a timeframe for developing New Source Performance Standards ("NSPS") for GHGs from electric generating units.[26] EPA plans to propose this NSPS in August 2011, and adopt the standard in June 2012.[27] In general, NSPS become applicable to new sources built after the effective date of the regulation, or affect what may be required to be included as an emission control at the time an existing source makes a change significant enough to trigger NSPS applicability.[28] To trigger the applicability of NSPS, an existing source must make a modification that increases its maximum hourly emissions rate. The Big Stone Plant is not a "new source," having been constructed in the early 1970s. In addition, the AQCS Project will substantially reduce emissions rates for SO_2, NO_X and particulate matter, while maintaining the same maximum hourly heat input rate (mmBtu/hour), which will keep the Plant's maximum hourly emissions of GHGs the same.[29] Thus, the AQCS Project will not trigger the applicability of the NSPS for GHGs that EPA plans to develop.[30]

At the same time EPA develops the NSPS, EPA also plans to issue emission guidelines for existing sources under CAA Section 111(d) ("111(d) Standard").[31] A 111(d) Standard, unlike the NSPS, applies to an existing source. States are given a period of time to develop plans to implement a 111(d) Standard, and if a state does not develop such a plan, EPA will prescribe a plan for that state. A "standard of performance" is defined as:

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26 *See* 42 U.S. C. § 7411(b) (CAA § 111(b)).

27 EPA plans to sign the proposed rule on July 26, 2011 and sign the final rule on May 26, 2012. *See* http://www.epa.gov/airquality/pdfs/boilerghgsettlement.pdf. The dates above estimate the month in which these actions will be published in the Federal Register.

28 42 U.S.C. § 7411 (CAA § 111). Under the NSPS program, new sources are those which begin construction or modification after the publication of proposed regulations. *Id.* at § 7411(a)(2) (CAA § 111(a)(2)).

29 The NSPS General Provisions also state that "[t]he addition or use of any system or device whose primary function is the reduction of air pollutants" is not "by itself" considered a "modification." 40 C.F.R.§ 60.14(e)(5) (except in the case of replacement of a control system with a less environmentally beneficial system).

30 Applicability of NSPS can also be triggered by "reconstruction" of a facility. "Reconstruction" occurs when components of an existing facility are replaced to such an extent that the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost required to construct a comparable new facility and it is economically and technically feasible to meet the NSPS. 40 C.F.R. § 60.15(b). The AQCS Project capital cost does not exceed 50 percent of the cost of building an entirely new Big Stone Plant, especially not where a newly built plant would require the same air pollution control systems, and where only parts of the AQCS Project replace existing equipment at the Plant, such as the baghouse.

31 42 U.S.C. § 7411(d) (CAA § 111(d)). An "existing source" is any source that is not a new source. *Id.* at § 7411(a)(6) (CAA § 111(a)(6)).

> …a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the [EPA] Administrator determines has been adequately demonstrated.[32]

Both NSPS and 111(d) Standards involve development of "standards of performance," but the 111(d) Standard also requires the EPA to consider, "among other factors, remaining useful lives of the sources in the category of sources to which such standard applies."[33] In general, the standards ultimately developed are more stringent for new sources than for existing sources because existing source standards need to consider the issues involved in retrofitting plants considering what can be achieved under their existing design.[34] The standards also need to be capable of attainment across the category of sources regulated by the standard.[35]

At present, standards of performance for GHGs, especially for existing sources, are anticipated to focus on efficiency improvements rather than add-on controls. The Co-owners have in the past implemented efficiency measures at Big Stone through its switch from lignite to PRB coal as fuel, and through installation of a more efficient steam turbine at the Plant. Additionally, the cost of efficiency improvements that achieve generation of the same amount of power with less fuel used could be offset in whole or in part by reduced fuel costs.

B. Greenhouse Gas Regulation Outside the Clean Air Act

Debate continues in Congress on the direction and scope of U.S. policy on climate change and regulation of GHGs. Although several bills have been introduced in Congress that would compel reductions of CO_2 emissions (for example the U.S. House of Representatives on June 26, 2009 passed the American Clean Energy and Security Act of 2009, also known as "Waxman-Markey"), no legislation establishing a comprehensive approach to mandatory GHG reductions passed the Congressional session that recently ended. The likelihood of any federal cap and trade reduction program being adopted by the new Congress in the near future appears doubtful. With the new Congress just beginning, the specific requirements of any such program are unknown. What is clear in the Legislative debates, as well as in the Waxman-Markey Bill, is that Congress places high emphasis on mitigation of costs for utility ratepayers, and would likely provide years of free allowance allocations for utilities for this purpose.[36]

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[32] *Id.* at § 7411(a)(1) (CAA § 111(a)(1)).

[33] *Id.* at § 7411(d)(2) (CAA § 111(d)(2)).

[34] As a retrofit control requirement, BART determinations take into account similar factors for the control of the pollutants from existing sources that impact visibility.

[35] NSPS apply nationally to an entire category of sources, in contrast to PSD BACT requirements, which are tailored on a case-by-case basis to the individual plant that is applying for a PSD permit.

[36] In the Waxman-Markey Bill, for example, the U.S. House provided free allowance allocations to utilities from a proposed program onset in 2012 through 2025, plus a gradual phase-in to purchased allowances for an additional five year period, until 2030.

IV. Coal Waste Regulation

On June 21, 2010, EPA published a proposed rule that outlines two possible options to regulate disposal of coal ash generated from the combustion of coal by electric utilities under the Resource Conservation and Recovery Act ("RCRA").[37] In one option, EPA would propose to list coal ash destined for disposal in landfills or surface impoundments as "special wastes" subject to regulation under Subtitle C of RCRA. Subtitle C regulations set forth the EPA's hazardous waste regulatory program, which regulates the generation, handling, transport and disposal of wastes.

The proposal would create a new category of special waste under Subtitle C, so that coal ash would not be classified as hazardous waste, but would be subject to many of the regulatory requirements applicable to hazardous wastes. This option would subject coal ash to technical and permitting requirements from the point of generation to final disposal. EPA is considering whether to impose disposal facility requirements such as liners, groundwater monitoring, fugitive dust controls, financial assurance, corrective action, closure of units, and post-closure care. This option also includes potential requirements for dam safety and stability for surface impoundments, land disposal restrictions, treatment standards for coal ash, and a prohibition on the disposal of treated coal ash below the natural water table. Beneficial re-uses of coal ash would not be subject to these requirements.[38]

Under the second proposed regulatory option EPA would regulate the disposal of coal ash under Subtitle D of RCRA, the regulatory program for non-hazardous solid wastes. In this option, EPA is considering issuing national minimum criteria to ensure the safe disposal of coal ash, which would subject disposal units to location standards, composite liner requirements, groundwater monitoring and corrective action standards for releases, closure and post-closure care requirements, and requirements to address the stability of surface impoundments. Within this option, EPA is also considering not requiring existing surface impoundments to close or install composite liners and allowing them to continue to operate for their useful life.

This option would not regulate the generation, storage, or treatment of coal ash prior to disposal, and no federal permits would be required.[39] EPA's proposal also states that EPA is considering whether to list coal ash as a hazardous substance under the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), and includes proposals for alternative methods to adjust the statutory reportable quantity for coal ash. EPA has not decided which regulatory approach it will take with respect to the management and disposal of coal ash.

The Big Stone Plant dry ash disposal site has been regulated, permitted and inspected by the South Dakota Department of Environment and Natural Resources (DENR) since the facility commenced commercial operation in 1975. The ash is currently transported to the site with conventional earthmoving equipment. The site is underlain with native clay. Each portion of the

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[37] 75 Fed. Reg. 35128 (June 21, 2010), Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities, Proposed Rule.

[38] *Id.* at 35133.

[39] *Id.*

designated disposal area is covered with clay and topsoil once it is filled to capacity. Monitoring of groundwater around the entire Plant site began prior to Plant operation and annual reports have been provided to the DENR. The site meets all current requirements of the DENR. While additional requirements may be imposed as part of EPA's pending rule that could increase the capital and operating costs of Big Stone Plant, identification of specific costs would be contingent on the requirements of the final rule.

The most costly option in the EPA proposal is the option that would regulate all coal ash destined for disposal as special waste. If EPA imposes this option, the Co-owners project a disposal cost of $37.50 per ton in 2010 dollars.[40] This would translate into a yearly cost of approximately $5.75 million, which if escalated at 3% to 2016, would be $6.66 million per year of additional O & M expense. If EPA chooses the other option, it would impose less cost than this estimate. It is also possible that the new regulations would not require change in the current operation and cost of Big Stone's coal ash disposal site.

V. Water Consumption and Water Pollution Control

A. Water Use

The Co-owners are not aware of any new or anticipated water use or water pollution requirements that would apply to the Big Stone Plant. Big Stone obtains water for plant operations from Big Stone Lake in accordance with the terms and conditions of Water Appropriations Permits that were issued by the South Dakota DENR. The current permitted water appropriations are adequate for the site needs following operation of the AQCS Project.

B. Stormwater Pollution Control Requirements

In South Dakota, any construction activity disturbing one or more acres must have coverage under a storm water permit. On December 31, 2009, the DENR reissued a General Permit for Storm Water Discharges Associated with Construction Activity. A General Permit is a standardized permit with pre-determined conditions for specific activities issued throughout the state. The storm water general permit includes runoff control requirements and work practices (e.g., grading and drainage requirements, silt fences, and retention ponds) designed to minimize impacts on surface waters associated with storm water runoff during construction activities. In connection with construction of the AQCS, Otter Tail Power Company, as operating agent, will need to file a Notification of Construction Activity and develop a Storm Water Pollution Prevention Plan as required by the General Permit.

All storm water discharges associated with industrial activities, including power generating facilities, that discharge through municipal storm sewer systems or that discharge directly into the waters of the U.S. are required to obtain a NPDES storm water permit. The storm water control and discharge requirements may require storm water retention, sampling, and analysis prior to discharge. In South Dakota, the DENR has a General Permit for Storm Water Discharges Associated with Industrial Activity. The permit covers anyone meeting the

[40] *Special Reliability Assessment: Resource Adequacy Impact of Potential U.S. Environmental Regulations*, at 57, NERC (October 2010).

conditions of the General Permit. Upon completion of the AQCS Project, the facility will be required to submit a Notice of Intent to apply for coverage under the General Permit for Storm Water Discharges Associated with Industrial Activity.

C. National Pollutant Discharge Elimination System Permit Requirements

In South Dakota, no person may directly discharge pollutants from any point source into surface waters of the state without a valid Surface Water Discharge ("SWD") permit.[41] The term "pollutant" is defined very broadly by the federal National Pollutant Discharge Elimination System ("NPDES") regulations and includes any type of industrial waste discharged into regulated surface waters of the U.S.

The Big Stone Plant is a zero liquid discharge facility and thus a NPDES permit is not required for this facility. The Plant utilizes a combination of retention ponds and wastewater treatment equipment that are designed to retain the process wastewater on-site and not discharge it to regulated surface waters. All retention ponds are manmade facilities that are briefly described as follows:

- A cooling pond – where the condenser cooling water is cooled prior to reuse in the Plant,
- An evaporation pond – which stores and evaporates water that is removed from the cooling pond for treatment, and
- A holding pond – which is the supply source for a portion of the wastewater treatment equipment as described below.

The current facility wastewater treatment system includes a brine concentrator that treats holding pond water similar to a still. The brine concentrator produces a high quality water that is used by both the Big Stone Plant and the adjacent POET Biorefining Ethanol Plant. The second brine concentrator effluent is a concentrated supernatant that is retained in a synthetically lined treatment pond. The current wastewater treatment system also includes a cold lime softener that chemically softens the water contained in the cooling pond. The combination of the storage ponds and the wastewater treatment systems have been designed to reuse water within the facility such that fresh makeup water consumption from Big Stone Lake is minimized.

The Co-owners will install a semi-dry FGD control system designed as a spray dryer absorber for SO_2 emissions control as part of the AQCS Project. There are no liquid wastes generated from a SDA control system, as all water used in the control system is evaporated. In fact, the SDA can provide an outlet for process wastewaters from other parts of the Plant. The AQCS Project therefore retains the zero liquid discharge design and operating criteria. Thus, a NPDES permit is not required as a result of the AQCS Project.

Section 316(b) of the Clean Water Act requires that the location, design, construction, and capacity of the cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The purpose of this regulation is to minimize the

41 S.D. Admin. R. 74:52:01:04. SWD permitting regulations are included in S.D. Admin. R., Article 74:52.

impingement and entrainment of fish and other aquatic organisms as they are drawn into a facility's cooling water intake. Those impacts are minimized by use of closed loop cooling technology. Closed loop cooling technology enables reuse of plant process cooling water within a predominately closed system as compared to once-through cooling process water cooling where the water is withdrawn from a public water body for cooling and then is immediately returned to the water body. EPA published its proposed rule in the *Federal Register* on April 20, 2011. Although EPA rulemaking with regard to Section 316(b) requirements is ongoing, the requirements of this section are not applicable to Big Stone Plant since the Plant is not regulated as a point source discharge under the NPDES permit program and it also uses a cooling pond, which is a type of closed loop cooling.

VI. CONCLUSION

This assessment of anticipated federal and state air quality regulations demonstrates that the Big Stone AQCS provides a sufficiently high level of control of the regional haze pollutants (SO_2, NO_X and particulate matter), such that no further control of these pollutants is reasonably anticipated to be required on the Plant after implementation of the AQCS Project. It is reasonably anticipated that additional control equipment for mercury, using Activated Carbon Injection as part of the AQCS system, will be required by the Utility MACT standard in the timeframe that the AQCS is implemented. The Co-owners have included the cost for mercury control and plans to implement this with the AQCS Project in anticipation of EPA's issuance of a Utility MACT standard.

The regulation of GHG under the CAA PSD program is not expected to impose additional control requirements on the Plant, while EPA's upcoming existing source standard is anticipated to focus on unit efficiency. The future of federal GHG legislation is unclear, and the potential requirements of such a program are unknown

This assessment of anticipated federal and state water and waste regulations demonstrates that there are no reasonably anticipated water quality regulations that would increase the costs to run the Plant. The proposed coal ash waste rules could impose a range of costs from no additional cost to some cost increases for coal ash waste disposal. The Co-owners have used a reasonable cost estimate based on NERC studies for the cost of coal waste disposal options EPA is considering. That cost, as well as the estimated cost for mercury control, is evaluated as part of the regulatory response scenario analysis in Joint Exhibit 3.

ATTACHMENT 3

ADMINISTRATIVE RULES OF SOUTH DAKOTA
CHAPTER 74:36:21

ARTICLE 74:36

AIR POLLUTION CONTROL PROGRAM

Chapter

CHAPTER 74:36:21

REGIONAL HAZE PROGRAM

Section

74:36:21:01. Applicability. The provisions of this chapter apply to the owner or operator of a new major source, modification to a major source, and a BART-eligible source. The provisions of this chapter do not apply to a major source or major modification to an existing source applicable to §§ 74:36:09 and 73:36:10.

Source:

General Authority: SDCL 34A-1-6.

Law Implemented: SDCL 34A-1-6.

74:36:21:02. Definitions. Unless otherwise specified, the terms used in this chapter mean:

(1) "Adverse impact on visibility," visibility impairment that interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the mandatory Class I federal area. Adverse impact on visibility shall be based on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency, and time of visibility impairment, and how these factors correlate with times of visitor use of a mandatory Class I federal area and the frequency and timing of natural conditions that reduce visibility;

(2) "BART," best available retrofit technology;

(3) "Best available retrofit technology" an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant that is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility that may reasonably be anticipated to result from the use of such technology;

(4) "BART-eligible source," an existing stationary facility;

(5) "Coal-fired power plant," any person, corporation, limited liability company, association, company, partnership, political subdivision, municipality, rural electric cooperative,

consumers power district, or any group or combination acting as a unit, owning or holding under lease, or otherwise real property used, or intended for use, for the conversion of coal into electric power;

(6) "Contribute to adverse impact on visibility," a change in visibility impairment in a mandatory Class I federal area of five-tenths deciviews or more, based on a 24-hour average, above the average natural visibility baseline. A source exceeds the threshold if the 98th percentile (eighth highest value) of the modeling results, based on one year of the three years of meteorological data modeled, equals or exceeds five-tenths deciviews;

(7) "Major source," as defined in § 74:36:01:08(2) and (3);

(8) "Mandatory Class I federal area," any area identified in 40 C.F.R. § 81, Subpart D (July 1, 2009); and

(9) "Visibility impairment," any human perceptible change in visibility such as light extinction, visual range, contrast, coloration, from that which would have existed under natural conditions.

Source:

General Authority: SDCL 34A-1-6.

Law Implemented: SDCL 34A-1-6.

74:36:21:03. Existing stationary facility defined. An existing stationary facility is any of the following stationary sources of air pollutants, including any reconstructed source that was not in operation before August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any air pollutant. In determining potential to emit, fugitive emissions, to the extent quantifiable, must be counted for:

(1) Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input;

(2) Coal cleaning plants (thermal dryers);

(3) Kraft pulp mills;

(4) Portland cement plants;

(5) Primary zinc smelters;

(6) Iron and steel mill plants;

(7) Primary aluminum ore reduction plants;

(8) Primary copper smelters;

(9) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(10) Hydrofluoric, sulfuric, and nitric acid plants;

(11) Petroleum refineries;

(12) Lime plants;

(13) Phosphate rock processing plants;

(14) Coke oven batteries;

(15) Sulfur recovery plants;

(16) Carbon black plants (furnace process);

(17) Primary lead smelters;

(18) Fuel conversion plants;

(19) Sintering plants;

(20) Secondary metal production facilities;

(21) Chemical process plants;

(22) Fossil-fuel boilers of more than 250 million British thermal units per hour heat input;

(23) Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels;

(24) Taconite ore processing facilities;

(25) Glass fiber processing plants; and

(26) Charcoal production facilities.

Source:

General Authority: SDCL 34A-1-6.

Law Implemented: SDCL 34A-1-6.

74:36:21:04. Visibility impact analysis. The owner or operator of a new major source or modification to a major source shall demonstrate to the department that the potential to emit from the new major source or modification to a major source will not contribute to adverse impact on visibility in any mandatory Class I federal area. The demonstration shall be based on visibility models approved in 40 C.F.R. § 51, Subpart W (July 1, 2009).

Source:

General Authority: SDCL 34A-1-6.

Law Implemented: SDCL 34A-1-6.

74:36:21:05. BART determination. The owner or operator of a BART-eligible source that emits any air pollutant which may reasonably be anticipated to contribute to adverse impact on visibility in any mandatory Class I federal area shall submit a BART determination. The BART determination shall follow the procedures outlined in 40 C.F.R. § 51, Subpart Y (July 1, 2009) and must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source. In this analysis, the BART determination must take into consideration the technology available, the costs of compliance, the energy and non air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility that may reasonably be anticipated to result from the use of such technology. The BART determination shall be submitted within nine months after being notified by the department that the existing stationary source is reasonably anticipated to contribute to adverse impact on visibility in any mandatory Class I federal area.

Source:

General Authority: SDCL 34A-1-6.

Law Implemented: SDCL 34A-1-6.

74:36:21:06. BART determination for a BART-eligible coal-fired power plant. The owner or operator of a BART-eligible coal-fired power plant may not cause or permit emissions of the following regulated air pollutant in excess of the following amounts:

(1) PM10 emissions in excess of 67.3 pounds per hour, which includes periods of startup and shutdown;

(2) PM10 emissions in excess of 0.012 pounds per million Btus, which includes periods of startup and shutdown;

(3) Sulfur dioxide emissions in excess of 505 pounds per hour, which includes periods of startup and shutdown;

(4) Sulfur dioxide emissions in excess of 0.09 pounds per million Btus, which does not include periods of startup and shutdown;

(5) Nitrogen oxide emissions in excess of 561 pounds per hour, which includes periods of startup and shutdown; and (6) Nitrogen oxide emission in excess of 0.10 pounds per million Btus, which does not include periods of startup and shutdown.

Compliance with the PM10 emission limits shall be based on an annual stack performance test using the average of three 1-hour test runs. Compliance with the sulfur dioxide and nitrogen oxide emission limits shall be based on using continuous emission monitoring systems and a 30-day rolling average.

Source:

General Authority: SDCL 34A-1-6.

Law Implemented: SDCL 34A-1-6.

74:36:21:07. Installation of controls based on visibility impact analysis or BART determination. The owner or operator of a new major source, modification to a major source, or a BART-eligible source that emits any air pollutant which may reasonably be anticipated to contribute to adverse impact on visibility in any mandatory Class I federal area shall install, operate, and maintain the controls established in a visibility impact analysis or BART determination. The owner or operator of a new major source or modification to a major source must install and operate the controls established in a visibility impact analysis at initial startup. The owner or operator of a BART-eligible source required to install BART must install, operate and demonstrate compliance with BART as expeditiously as practicable, but no later than five years from EPA's approval of the state implementation plan for regional haze.

Source:

General Authority: SDCL 34A-1-6.

Law Implemented: SDCL 34A-1-6.

74:36:21:08. Operation and maintenance of controls. The owner or operator required to install and operate controls established in a visibility impact analysis or BART determination shall establish written procedures to ensure the control equipment is properly operated and maintained. The written procedures shall include, at a minimum, the following:

(1) A maintenance schedule for each control device that is consistent with the manufacturer's instructions and recommendations for routine and long-term maintenance;

(2) Procedures for the proper operation and maintenance of each control device; and

(3) Parameters to be monitored to determine each control device is being operated properly.

Source:

General Authority: SDCL 34A-1-6.

Law Implemented: SDCL 34A-1-6.

74:36:21:09. Monitoring, recordkeeping and reporting. The owner or operator required to install and operate controls established in a visibility impact analysis or BART determination shall conduct periodic monitoring, recordkeeping, and reporting. All sulfur dioxide and nitrogen oxides emissions from the BART-eligible source shall be routed to the main stack of a BART-eligible source. Monitoring of sulfur dioxide and nitrogen oxide emissions from the main stack shall be conducted using a continuous emission monitoring system which complies with the continuous emission monitoring requirements in § 74:36:13. Monitoring requirements for other air pollutants from a BART-eligible source or from a major source or modification of a major source shall be in accordance with § 74:36:05:16.01(9). Recordkeeping and reporting shall comply with the requirements in § 74:36:05:16.01(9).

Source:

General Authority: SDCL 34A-1-6.

Law Implemented: SDCL 34A-1-6.

74:36:21:10. Permit to construct. The owner or operator subject to this chapter may be issued a permit to construct in accordance with § 74:36:20 if the department determines that the new major source or modification to a major source does not contribute to adverse impact on visibility at a mandatory Class I federal area.

Source:

General Authority: SDCL 34A-1-6.

Law Implemented: SDCL 34A-1-6.

74:36:21:11. Permit required for BART determination. The owner or operator of a BART-eligible source shall submit an application in accordance with § 74:36:20 to include the controls, emission limits, monitoring, recordkeeping, and reporting requirements identified in the BART determination and approved by the department.

Source:

General Authority: SDCL 34A-1-6.

Law Implemented: SDCL 34A-1-6.

74:36:21:12. Federal land manager notification and review. The department shall provide written notice to the federal land manager of a BART determination or any permit application for a new major source or modification to a major source if the emissions from which may contribute to adverse impact on visibility at a mandatory Class I federal area, except for an application submitted in accordance with §§ 74:36:09 or 74:36:10. A notification of a BART determination shall include a copy of the BART determination and must be submitted within 30 days of receipt of a complete BART determination. The department shall consider an analysis performed by the federal land manager submitted within 60 days of the federal land manager's being notified of a BART determination or by the end of the public participation process, whichever is later. A permit application for a new major source or modification to a major source shall include a copy of the permit application and visibility impact analysis. The department shall consider an analysis performed by the federal land manager submitted within 30 days of the federal land manager being notified of a visibility impact analysis or by the end of the public participation process, whichever is later. The department shall follow the procedures outlined in §§ 74:36:09 or 74:36:10 for an application submitted in accordance with §§ 74:36:09 or 74:36:10.

Source:

General Authority: SDCL 34A-1-6.

Law Implemented: SDCL 34A-1-6.

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ATTACHMENT 4

SO_2, NO_X, AND MERCURY REDUCTION STUDY

Sargent & Lundy LLC

Kenneth A. Mixer
Project Manager
312-269-2235
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September 24, 2010
Project No. 12715-001
Letter No. BSP-SL-OTP-0013

Otter Tail Power Company
Big Stone Plant

SL-010408 Draft Report
SO_2, NO_x, and Mercury Reduction Study
Conceptual Engineering Design Report

Mr. Mark Rolfes
Otter Tail Power Company
215 S. Cascade Street
Fergus Falls, MN 56538-0496

Dear Mr. Rolfes:

Enclosed is the draft SO_2, NO_x, and Mercury Reduction Study for your comments. We look forward to walking you through the results and answer any questions you may have.

Please do not hesitate contacting me if you have any questions.

Yours very truly,

Ken A. Mixer
Project Manager

KAM:km
Enclosure – All Recipients
File No. 2.03
BSP-SL-OTP-0013.doc

OTTER TAIL POWER COMPANY

BIG STONE PLANT

SO_2, NO_X, AND MERCURY REDUCTION STUDY

CONCEPTUAL ENGINEERING DESIGN REPORT

SL-010408
Draft Report

September 24, 2010
Project 12715-001

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

LEGAL NOTICE

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TABLES AND FIGURES

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APPENDIXES

ABBREVIATIONS AND ACRONYMS

Abbreviation or Acronym	Explanation
acfm	actual cubic feet per minute
ACI	activated carbon injection
AFUDC	allowance for funds used during construction
AHJ	Authority Having Jurisdiction
AIG	ammonia injection grid
AQCS	air quality control system
ARSD	Administrative Rules of South Dakota
[TRADE SECRET DATA BEGIN	TRADE SECRET DATA ENDS]
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BOP	balance-of-plant
Btu	British thermal unit
BC	brine concentrator
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCR	coal combustion residual
CFB	circulating fluidized bed combustor or combustion
CFR	Code of Federal Regulations
CLS	cold-lime softener
CO	carbon monoxide
D/F	dioxin/furan
DCS	distributed control system
DENR	Department of Environment and Natural Resources (South Dakota)
EEGT	economizer exit gas temperature
EGU	electric generating unit
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
FD	forced draft
FGD	flue gas desulfurization
FGR	flue gas recirculation
FM	Factory Mutual
GA	general arrangement
GHG	greenhouse gas
H_2	hydrogen

ABBREVIATIONS AND ACRONYMS

Abbreviation or Acronym	Explanation
H_2O	water
HAP	hazardous air pollutant
HHV	higher heating value
HMI	human-machine interface
hp	horsepower
hr	hour
I/O	input/output
ICR	Information Collection Request
ID	induced draft
in. w.c.	inches water column
lb	pound
LPA	large-particle ash
LSD	lime spray dry
LSFO	limestone forced oxidation
MACT	Maximum Achievable Control Technology
MCR	maximum continuous rating
MBtu	million British thermal unit
MW	megawatt
MWh	megawatt-hour
N_2	nitrogen gas
NAAQS	National Ambient Air Quality Standard(s)
NEMA	National Electrical Manufacturers Association
NFPA	National Fire Protection Association
NH_3	ammonia
NO_2	nitrogen dioxide
NOI	Notice of Intent
NO_X	Nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NPRM	Notice of Proposed Rulemaking
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	operations and maintenance
O_2	oxygen
OEM	original equipment manufacturer

ABBREVIATIONS AND ACRONYMS

Abbreviation or Acronym	Explanation
OFA	overfire air
OSHA	Occupational Safety and Health Administration
PAC	powder-activated carbon
PC	pulverized coal
PLC	programmable logic controller
PM	particulate matter
ppm	parts per million
ppmv	parts per million volume
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
psia	pounds per square inch absolute
psig	pounds per square inch gauge
RAT	reserve auxiliary transformer
RCRA	Resource Conservation and Recovery Act
RO	reverse osmosis
RPS	Renewable Portfolio Standards
RTD	resistance temperature detector
SCR	selective catalytic reduction
SDA	spray dry absorber
SIP	state implementation plan
SNCR	selective non-catalytic reduction
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SOFA	separated overfire air
SWD	surface water discharge
TiO_2	titanium oxide
UAT	unit auxiliary transformer
UPS	uninterruptible power supply
V_2O_4	vanadium tetroxide
V_2O_5	vanadium pentoxide
VFD	variable-frequency drive
wacfm	wet actual cubic feet per minute

1. EXECUTIVE SUMMARY

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Otter Tail Power Company (OTP) is required to install Air Quality Control System (AQCS) equipment at its Big Stone Plant (Big Stone or the plant) to reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) based on a Best Available Retrofit Technology (BART) determination filed by the South Dakota Department of Environment and Natural Resources (DENR). The BART requires the AQCS system to include flue gas desulfurization (FGD) for SO_2 reduction, and selective catalytic reduction (SCR) with separated overfire air (SOFA) for NO_X reduction. BART did not include mercury reduction requirements; however, because it is expected that the utility Maximum Achievable Control Technology (MACT) will require about reduction when implemented by the end of 2011, mercury reduction technology was also evaluated. The AQCS retrofit work is to be completed by the end of 2015 and the South Dakota DENR determination states that the retrofit AQCS system must be operational by January 15, 2016.

The AQCS system proposed for the conceptual design as presented herein will allow Big Stone to operate within the emissions limits listed in Table 1-1.

Table 1-1. Emission Levels

Parameter	Value
PM (filterable)	
SO_2	
NO_X	
Hg	

TRADE SECRET DATA ENDS]

At OTP's request, Sargent & Lundy, L.L.C. (S&L) conducted a conceptual design study and prepared estimated costs for the AQCS needed to comply with the South Dakota DENR BART determination. The AQCS retrofit proposed comprises a dry FGD system with new baghouse, SOFA, anhydrous-based SCR, ACI, and the associated ancillary balance-of-plant (BOP) systems.

The capital costs of the AQCS retrofit were estimated separately, one for NO_X-related work (SCR and SOFA) and one for SO_2 related work (dry FGD with a baghouse and ACI). The costs are summarized in Table 1-2.

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Table 1-2. Capital Cost Summary

Parameter	SCR	Dry FGD with New Baghouse
Direct and construction indirect cost,		
Indirect cost,		
Contingency @		
Escalation,		
Owner's cost,	Included in dry FGD	
Total project cost, $M		
Total AQCS Cost,		

The capital cost represents completion of installation in the summer of and a commercial operation date of . The estimate is based on current market prices and escalation is included to reflect the operation date. The estimate does not include extra contingency for escalation that can occur due to excessive cost increases in equipment, material, or labor. Such escalation occurred between 2005 and 2008, when all utility projects were paying premiums because of the excessive escalation that applied over all utility projects. The Big Stone AQCS project appears to be ahead of other potential AQCS projects that could be initiated as the environmental regulations become more defined in 2011. Specifically, it is anticipated that AQCS vendors and construction contractors will become increasingly busy as these new projects are initiated, which could result in market-related price increases. It is recommended that OTP consider steps to avoid or minimize the impact of market escalation. Awarding contracts as early as possible may position OTP ahead of the other utilities also retrofitting AQCS equipment.

The first-year and total levelized O&M costs are summarized in Table 1-3.

Table 1-3. First-Year O&M Costs

Parameter	SCR	Dry FGD with New Baghouse
First-Year Fixed O&M,		
First-Year Variable O&M,		
Total First-Year O&M,		
Levelized O&M,		

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The outage required in weeks. This outage is based on the boiler modifications being the critical path. The boiler modifications need to be evaluated in more detail if it is desired to shorten the outage length.

The permitting evaluation considered whether other environmental rules or regulations might alter the BART requirements for AQCS retrofit. In our opinion, the proposed dry FGD with baghouse and SCR could be considered Best Available Control Technology (BACT) for a new sub-bituminous-fired unit, and the ACI system should meet future MACT requirements. OTP installing dry FGD with baghouse, SCR, and ACI as a retrofit, in our judgment, will meet the regulations expected for the next years.

Two major issues needed evaluation in order to complete the above detailed conceptual design scenarios. A screening study was completed that evaluated (1) three options using wet FGD or dry FGD systems and (2) two locations where the SCR reactor could be built. With the detailed conceptual cost estimate completed, these decisions were reviewed to ensure that the decisions had not changed. The screening study cost results are shown in Table 1-4.

Table 1-4. Capital Cost Summary (All FGD Options with SCR Behind Boiler)

Parameter	Option 1, Dry FGD with Existing Baghouse and SCR	Option 2 Dry FGD with New Baghouse and SCR	Option 3 Wet FGD with Existing Baghouse and SCR
FGD,			
SCR,			
Total Capital Cost,			
Delta,			

TRADE SECRET DATA ENDS]

A dry FGD system that uses a new baghouse was the least-cost option for FGD. A second dry FGD option reuses the existing baghouse. As the costs used in the screening study did not change significantly, the previously determined cost difference remains. Dry FGD with a new baghouse is still the recommended FGD system for Big Stone. This technology option offers the lowest cost and lowest risk of cost increase due to unknowns associated with reinforcing a majority of the ductwork and structures, and will be able to follow load without significant O&M issues. The option of reusing the existing baghouse has significant cost issues related to reinforcing structures, has higher risk of cost increase and extending the outage, and has significant risk of increasing O&M because of the solids that could drop out in the ducts ahead of the baghouse.

The second major issue for the Big Stone AQCS retrofit is where to locate the SCR. The screening recommended the location the SCR immediately behind the boiler. This location usually is cost-effective when evaluating SCR on utility boilers. The concern was that if significant boiler steel had to be modified to tie in the SCR, this location's costs might increase. During the conceptual design, several trips were made to evaluate the SCR location and the conclusion is that it can be retrofit without the impacts that were initially considered problematic in the screening study. The detailed conceptual design confirms the SCR located behind the boiler is optimal.

Other screening studies were completed, and used to focus the conceptual design effort to a final general arrangement and design. While these screening studies did not have the impact of the wet versus dry FGD study, they were important to completing the effort. Table 1-5 below lists the mini studies and summarizes the major conclusions.

The next steps for moving the project forward are:

- Authorize the project to proceed with design of the AQCS retrofit
- Start permitting of the project
- Start detailed design of the project
- Review solutions to reduce the cost of lowering economizer outlet and SCR inlet services

Table 1-5. Summary of Screening Studies Completed for Conceptual Design

Study	Conclusion
Location of SCR (Appendix B)	The SCR reactor located behind the boiler is more cost-effective than located to the side of the unit (south).
SCR Reagent Study (Appendix E)	Using anhydrous ammonia is lowest cost compared with urea and aqueous ammonia. Anhydrous ammonia is potentially more dangerous, but when the safety features are factored in, is cost-effective. This study should consider when SOFA is used because the SCR will require less reagent.
In-Boiler NO_X Reduction (Appendix F)	Two SOFA approaches were developed. The greater capital cost approach was included because it allows the lowest economizer outlet NO_X. However, outlet NO_X level is only marginally lower, so these two systems will be evaluated in detailed design.
[TRADE SECRET DATA BEGINS Economizer Gas Outlet Temperature Reduction (Appendix F)	recommended several internal boiler modifications to control the temperature to between 750°F and 625°F. The modifications are expensive, at about in capital. These costs and alternative approaches will be considered during detail engineering.
Wet v. Dry FGD (Appendix B)	Dry FGD is significantly more cost-effective than wet FGD. The PRB fuel with low-sulfur content typically favors this outcome on middle-sized installations. A new baghouse is the lowest risk compared to reusing the existing baghouse. The costs are similar, but favor a new baghouse as well.
Solid Waste Handling (Appendix M)	A pneumatic solid waste handling system will transport solids (FGD waste and fly ash) to a new silo located next to the existing silo. Both silos will be used. Scrapers and articulated trucks will then be used to transport the ash to the onsite landfill. It is not cost-effective to transport the solids to the landfill pneumatically.
Water Balance and Brine Concentrator (Appendix D)	Installing a reverse osmosis system is cost-effective compared to continued operation of the brine concentrator. The brine uses considerably more power, which makes it more costly than building the new reverse osmosis (RO) system.
NFPA 85 Compliance (Appendix C)	Reinforcing the boiler and air heater is recommended to avoid the risk of implosion. The new fans will be capable of pulling double the negative pressure of the existing fans and this increases the risk of implosion. The current boiler is designed for a very low pressure, +3/-7, and using controls to protect the boiler is very risky. provided a budgetary cost of reinforcement, which is included in the cost estimate. TRADE SECRET DATA ENDS]
Selection of ID Fan (Appendix G)	Two centrifugal fans are recommended with variable-frequency drives (VFD). Two fans rather than four are less costly to install. Using VFD technology allows power savings at low load operation.
Mercury Reduction Evaluation (Appendix L)	Activated carbon injection (ACI) is the recommend method to reduce mercury. ACI can achieve 90% reduction when injected ahead of the dry FGD system with baghouse. Specific requirements for mercury reduction are not yet known, but are expected to be established in 2011, which would be applicable to the Big Stone retrofit work.

2. BASIS OF STUDY

2.1 PURPOSE

Prior to development of the conceptual engineering study as presented herein, S&L performed a screening study to determine which SO_2 technology (wet vs. dry) and which SCR location (behind the boiler vs. south of the boiler) would be the optimal choice for Big Stone. The screening study concluded that dry FGD with SCR located directly behind the boiler was the best approach. Details of the screening study (SL-010303) are provided in Appendix B.

The primary drivers for the project are the regulatory requirements associated with the Regional Haze Rule, which was promulgated to protect the visibility in national parks, national forests, and other national areas. OTP submitted a BART study to the South Dakota DENR that stated Big Stone needed to implement technology to reduce sulfur dioxide (SO_2) and oxides of nitrogen (NO_X) emissions.

The work was done using a step-by-step approach. The first step was to prepare several mini studies that focused on the overall conceptual design scope. Table 2-1 lists the mini studies and summarizes the major conclusions.

Table 2-1. Summary of Screening Studies Completed for Conceptual Design

Study	Conclusion
Location of SCR (Appendix B)	The SCR reactor located behind the boiler is more cost-effective than located to the side of the unit (south).
SCR Reagent Study (Appendix E)	Using anhydrous ammonia is lowest cost compared with urea and aqueous ammonia. Anhydrous ammonia is potentially more dangerous, but when the safety features are factored in, is cost-effective. This study should consider when SOFA is used because the SCR will require less reagent.
In-Boiler NO_X Reduction (Appendix F)	Two SOFA approaches were developed. The greater capital cost approach was included because it allows the lowest economizer outlet NO_X. However, outlet NO_X level is only marginally lower, so these two systems will be evaluated in detailed design.

[TRADE SECRET DATA BEGINS

Economizer Gas Outlet Temperature Reduction (Appendix F)	recommended several internal boiler modifications to control the temperature to between 750°F and 625°F. The modifications are expensive, at about in capital. These costs and alternative approaches will be considered during detail engineering.
Wet v. Dry FGD (Appendix B)	Dry FGD is significantly more cost-effective than wet FGD. The PRB fuel with low-sulfur content typically favors this outcome on middle-sized installations. A new baghouse is the lowest risk compared to reusing the existing baghouse. The costs are similar, but favor a new baghouse as well.
Solid Waste Handling (Appendix M)	A pneumatic solid waste handling system will transport solids (FGD waste and fly ash) to a new silo located next to the existing silo. Both silos will be used. Scrapers and articulated trucks will then be used to transport the ash to the onsite landfill. It is not cost-effective to transport the solids to the landfill pneumatically.
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TRADE SECRET DATA ENDS]

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Mercury Reduction Evaluation (Appendix L)	Activated carbon injection (ACI) is the recommend method to reduce mercury. ACI can achieve 90% reduction when injected ahead of the dry FGD system with baghouse. Specific requirements for mercury reduction are not yet known, but are expected to be established in 2011, which would be applicable to the Big Stone retrofit work.

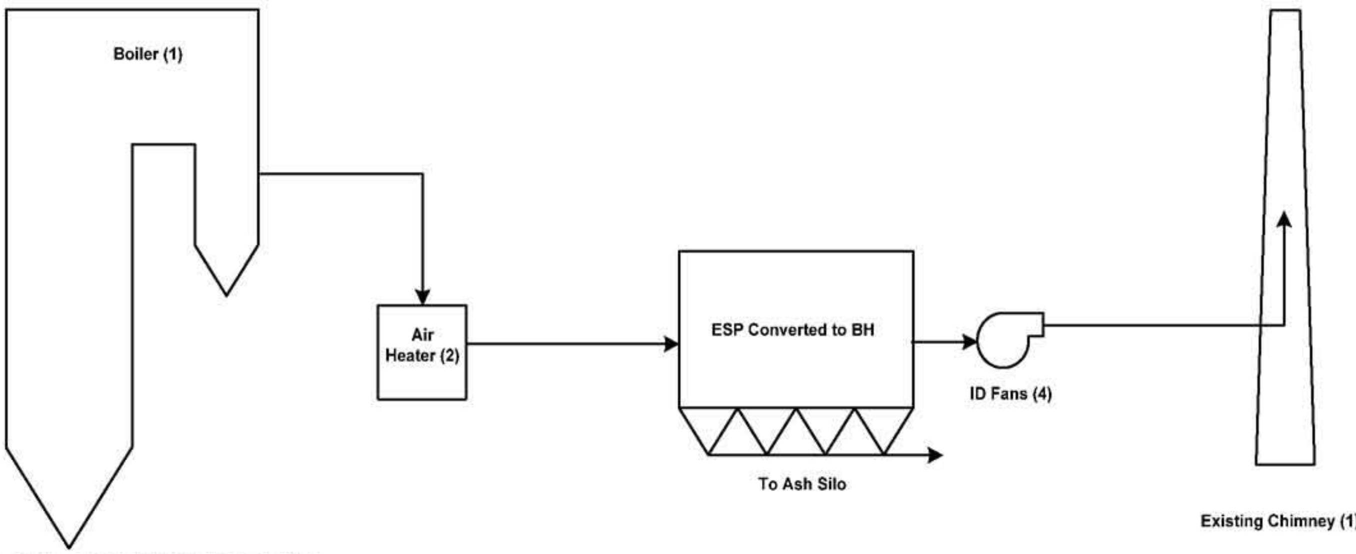
After completion of the mini studies, the conceptual design was completed as presented herein. This report addresses the following:

- Conceptual design with general arrangement (GA) drawings for dry FGD, SCR, and ACI, and technology screening and SCR location
- National Fire Protection Association (NFPA) 85 compliance
- Balance-of-plant (BOP) issues such as water treatment, ammonia delivery, boiler modifications, and fan selection
- Electrical single-line diagram
- Piping interconnection
- Implementation schedule and cash flow
- Capital and O&M cost estimates
- Permitting evaluation
- Constructibility review
- Next steps toward project implementation

2.2 EXISTING EQUIPMENT

Figure 2-1 depicts the existing equipment arrangement at Big Stone in the form of a simplified process flow diagram (PFD).

Figure 2-1. Existing Big Stone Equipment Arrangement



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The Big Stone boiler was originally designed to burn lignite fuel and began operation in 1975. Designed by , the boiler is a Caroline-type balanced-draft pump-assisted radiant machine. The cyclone furnace originally included a predry system with hammer mill crushers on each fuel delivery circuit. In 1995, the boiler was converted to burn Powder River Basin (PRB) fuel. With the conversion to PRB fuel, the NO_X emissions rose significantly and the predry system was removed to allow for a simplified SOFA system to be installed in the existing predry ports. The boiler also has a flue gas recirculation (FGR) system to control main steam and reheat temperatures. Since the FGR fan capacity was reduced, the unit operates using only one of the two gas recirculation fans.

From the boiler, flue gas travels to two regenerative-type, vertical-shaft air heaters, each equipped with secondary and primary air ducts. The unit was originally designed with an electrostatic precipitator (ESP). In 2001, the ESP was converted to an system, whereby it functioned both as an ESP and fabric filter for particulate control. This system was the first of its kind and the installation was to demonstrate the technology. However, there were operational problems with the demonstration

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technology, which resulted in conversion of the entire particulate collector to a conventional pulse-jet fabric filter in 2007. Ash is currently sent to a fly ash storage silo located directly south of the plant, where it is then trucked to a landfill. Flue gas from the fabric filter flows to four centrifugal induced draft (ID) fans. There were no ID fan changes at the time of the conversion of the ESP to a fabric filter. Currently, the unit is ID fan-limited and does not have the capability of being upgraded to overcome the additional pressure drop. The ID fans discharge the flue gas to the chimney, which has two breech openings.

2.3 UNIT DESIGN BASIS

Big Stone is a 495-MW (gross) cyclone furnace that fires PRB coal. S&L initiated its evaluation using the unit's maximum design permitted heat input, as provided by OTP, to generate mass balances. The heat input to the unit is a primary parameter used to calculate the quantity of flue gas that would need treatment. The amount of flue gas that needs to be treated is one of the parameters used to size various emission control technology equipment. Since the amount of flue gas would increase parallel with the heat input, the maximum design permitted heat input was used as the basis for the sizing of equipment and the capital cost estimates. The equipment sizing and design basis using the more typical operating heat input can be reviewed further during detail engineering. The design basis parameters used in this evaluation are listed in Table 2-2.

Note that Big Stone, designed for base load service, is located in a region with significant wind-generated power potential. With the development of wind farms, OTP anticipates a shift in the Big Stone load profile toward more frequent cycling duty, meaning daily operation at loads of 50% maximum continuous rating (MCR) and lower. This study takes into account daily cycling of the unit.

Table 2-2. Design Basis Parameters

Parameter	Value
MCR output, MW	495
Heat input, MBtu/hr	5,609
O_2 at economizer outlet, vol %	2.50
Air heater in-leakage, wt % of total	15
Humidity, lb/lb dry air	0.025
Fly ash/bottom ash split	50:50

2.4 FUEL INFORMATION

The conceptual engineering study is based on burning typical PRB coal. OTP provided numerous ultimate and proximate analyses to S&L, based on which, a typical operating coal was defined. Any of the options considered can provide good SO_2 control for the typical range of PRB coals available. Table 2-3 identifies the design fuel analysis used in the study.

Table 2-3. Design Fuel Analysis

Parameter	Value (wt%)
Carbon	49.86
Hydrogen	3.60
Nitrogen	0.72
Sulfur	0.40
Oxygen	12.05
Chlorine	0.01
Fluorine	0.01
Moisture	27.35
Ash	6.00
HHV, Btu/lbs	8,200

2.5 OPERATING CONDITIONS

The operating conditions used for the conceptual engineering study are defined in Table 2-4.

Table 2-4. Current Operating Conditions

Parameter	Value
Average SO_2 emissions, lbs/MBtu	0.92
Average NO_X emissions, lbs/MBtu	0.80
Average Hg emissions, lbs/TBtu	8.00
Startup fuel	#2 Fuel Oil

Parameter	Value
100% MCR:	
Coal feed rate (ton/hr)	685,000
Total flue gas flow at air heater outlet, acfm	2,427,000
Average flue gas temperature at air heater outlet, °F (±25°F)	325
Average pressure at air heater outlet, in. H_2O	-19.5
40% MCR (minimum load):	
Total flue gas flow at air heater outlet, acfm	878,000
Average flue gas temperature at air heater outlet, °F (±25°F)	250
Average flue gas pressure at air heater outlet, in. H_2O	-10.0

2.6 ECONOMIC INFORMATION

Table 2-5 lists the major economic parameters that were used in the variable O&M costs as well as the economic evaluations throughout the study. These values were developed both by OTP and S&L.

Table 2-5. Major Economic Parameters [TRADE SECRET DATA BEGINS

Parameter	Value
Amortization life,	
Interest rate for discounting,	
Capital escalation rate,	
O&M escalation rate,	
Levelized fixed charge rate,	
Capacity factor,	
Auxiliary electric power energy charge,	
Ash disposal cost (placement only),	
Water,	
Lime (truck delivery),	
Activated carbon (truck delivery),	
Anhydrous ammonia (truck delivery),	

TRADE SECRET DATA ENDS]

3. CONCEPTUAL DESIGN FOR SCR, DRY FGD, AND ACI

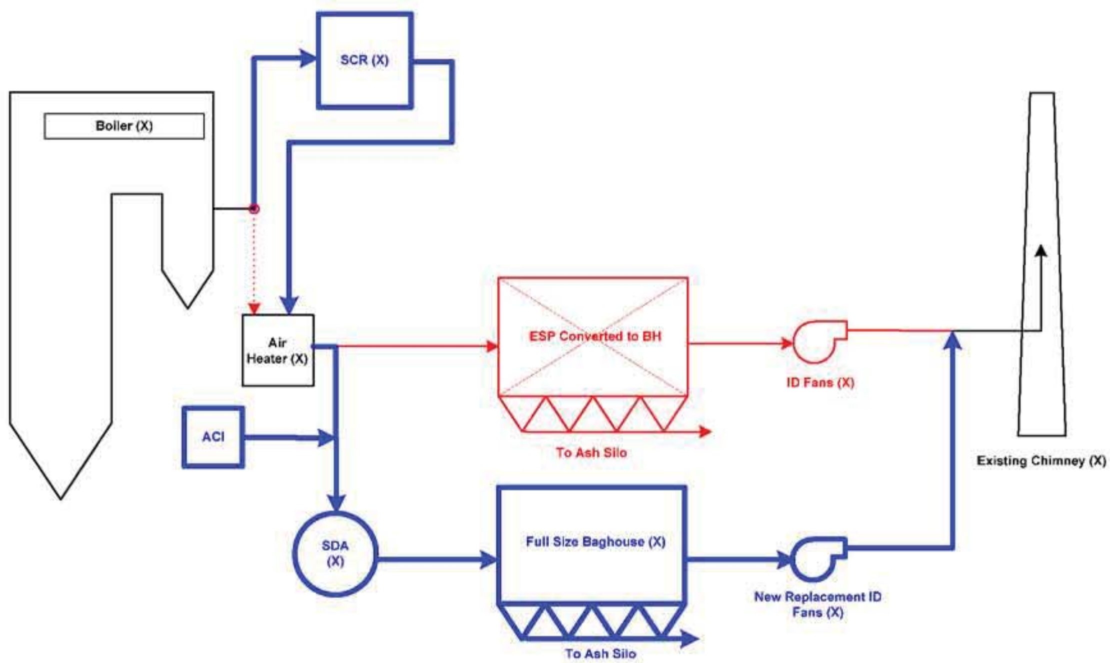
3.1 DESCRIPTION OF MODIFICATIONS

3.1.1 Process Flow

[TRADE SECRET DATA BEGINS

Figure 3-1 is a PFD depicting the installation of the SCR, dry FGD and ACI systems. The new equipment installed for the project is shown in blue and equipment taken out of service in red. Flue gas will travel from the two outlets of the economizer to SCR reactors. Ductwork will be routed from the outlet of the SCR back to the air heater. There will be no bypass around the SCR for startup or low-load operation. Flue gas will then travel from the outlet of the air heaters through a long duct to the spray dry absorbers (SDAs). Activated carbon will be injected in the ductwork ahead of the SDAs. The flow will then travel from the new SDAs to new baghouses, per absorber. Finally, the flue gas will travel to new replacement ID fans, per baghouse/absorber combination, then to the existing chimney. TRADE SECRET DATA ENDS]

Figure 3-1. SCR, Dry FGD, and ACI Process Flow Diagram



3.1.2 General Arrangements

A preliminary set of general arrangement (GA) drawings are shown in Appendix A. The drawings show the layout of the major AQCS equipment for the project based on preliminary sizing of the equipment, ductwork, and buildings. The existing and new structures were modeled three-dimensionally (3-D). Walkdowns were performed to ensure there were no major discrepancies between the existing design drawings and the actual conditions. In addition, a walkdown of the plant was performed specifically to review the constructibility of the new systems using the most up-to-date of these GA drawings.

[TRADE SECRET DATA BEGINS

The GA drawings show the SCR installed after the economizer and before the air heater. The SCR system includes the SCR inlet ductwork, SCR reactors, SCR outlet ductwork, and an ammonia storage and forwarding system. The location of the SCR reactors is relatively close to the boiler economizer outlet on the west side of the boiler. SCR reactors are supported by structural steel trusses spanning north-south over the existing baghouse and baghouse inlet ductwork. There are catalyst levels in each SCR reactor, with sootblowers on the and sonic horns on . An enclosure (roof, siding, and floors) will surround all SCR access areas and the ammonia injection grid (AIG) area. The ammonia storage and forwarding system is located south of the plant near the other material loading and unloading areas. This location was chosen based on the prevailing wind directions shown on the wind rose in the area of Big Stone plant. The prevailing winds are generally in the plant east-west direction and in the event that there is an ammonia leak, plant personnel will frequently be outside of the immediate area of impact.

The dry FGD system, including new baghouses, blower building, and ID fans with variable-frequency drives (VFDs) are located south of the existing baghouse and chimney. The inlet ductwork for the dry FGD system will tie in at the existing baghouse inlet ductwork and the outlet of the new ID fans will tie in at the existing expansion joints located at the chimney breeching. These tie-ins will be performed during the spring plant outage. The existing baghouses and ID fans will be demolished starting with the spring outage. This will allow the space to be used for the water treatment building and a makeup water storage tank. TRADE SECRET DATA ENDS]

The lime storage system, reagent preparation (lime slurry and recycle ash) system, and solid waste storage system are located near the south side of the dry FGD and baghouse systems. With this arrangement, material loading and unloading is generally centralized in one location and these systems are readily accessible to the process equipment using the overhead pipe rack. As part of these systems, an enclosed slurry sump basin is shown west of the recycle building. The basin will be used for flushing, washdown, and clean out of the recycle and lime slurry systems. Once the solids in the basin settle, the water can be recovered and reused in the process and the solids can be sent to the landfill.

The ACI system silo and ACI prefabricated electrical building are located east of the dry FGD system inlet ductwork. The ACI injection grid is located to the north of the SDAs in the top of the inlet ductwork. Piping and conduit for the ACI system will be supported above grade by the ductwork support steel and, if necessary, by a short pipe rack from the ACI silo to the duct support steel.

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An auxiliary power upgrade is being provided for the AQCS equipment. New equipment for the auxiliary power upgrade is located east of the turbine building and consists of a 230-kV line coming in from the switchyard to a reserve auxiliary transformer (RAT) and a unit auxiliary transformer (UAT) that ties in to the existing isolated phase bus tap. These transformers will be connected by above-grade cable bus to 13.8-kV switchgear in the prefabricated main electrical power distribution building located along the south side of the boiler building. Electrical power distribution will be provided by electrical equipment located within prefabricated electrical power distribution buildings, which include the main electrical power distribution building, a lime preparation and recycle electrical building, and a baghouse electrical building. As shown on the GA drawings, these buildings are strategically located near the new electrical loads. Each of the prefabricated buildings will be elevated approximately 4-5 feet above grade to allow bottom-cable tray entry. TRADE SECRET DATA ENDS]

The main pipe rack shown on the GA drawings generally runs north-south between the equipment and buildings. The pipe rack will be used for routing above-ground piping, cable trays, and conduits.

Storage for the AQCS equipment spare parts will be provided in a new pre-engineered warehouse located northwest of the chimney and near the existing plant warehouse area.

All structures will be enclosed and access will be provided by stairways and walkways from the existing and new structures. One six-person elevator will also be provided near the north SDA, which will have elevator stops to the SDA penthouse and each of the SCR catalyst levels.

3.2 BOILER MODIFICATIONS

3.2.1 Separated Overfire Air

Operating cyclone-equipped boilers at reduced airflow or at substoichiometric conditions (less air than is theoretically required for complete combustion) substantially minimizes/reduces fuel NO_X formation. With the unique combustion characteristics of a cyclone furnace, significant NO_X reduction at an overall lower cost can be realized by air staging techniques.

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Based on a study conducted by (see Appendix F), two potential SOFA designs that provide optimum mixing of the balance of combustion air with the main combustion zone flue gas during the second stage of combustion with the furnace region (i.e., the burnout zone) were reviewed.

- Option 1 – SOFA at existing FGR elevation 1202'-9": 12 SOFA ports with windbox takeoffs.
- Option 2 – SOFA at higher elevation 1254'-0": 14 SOFA ports and duct runs with front and rear plenum plus platform and stairway additions/modifications.

The difference in NO_X performance between the two SOFA port elevation locations is currently projected to be only about . However, the estimated budgetary capital costs and schedule for the two options vary considerably as discussed in Appendix F. For the conceptual design, Option 2 was chosen and included in the capital cost estimate. During detail engineering, the lower-cost Option 1 will be evaluated further.

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3.2.2 Economizer Exit Gas Temperature Control

For the SCR catalyst to operate efficiently, the bulk average gas temperature leaving the economizer needs to be no greater than 750°F with variation of less than +20°F at a "dirty" boiler condition at full load (3,638,000 lbs/hr main steam flow) and greater than 625°F with variation of less than -20°F at a "clean" boiler condition at minimum load (1,627,000 lbs/hr main steam flow).

The economizer exit gas temperature (EEGT) at full load and clean boiler conditions is currently 792°F and the unit is not achieving the 1005°F steam temperatures. The EEGT at minimum load is currently 645°F. Therefore, in order to achieve an acceptable temperature range for the SCR catalyst to operate efficiently, convection pass modifications are required as shown in Appendix F.

The convection pass modifications consist of the following major modifications:

- New reheat and inlet bank, including an additional reheat pendant superheater bank for increased total surface area.
- New primary superheater, including an additional horizontal primary superheater bank for increased total surface area. [TRADE SECRET DATA BEGINS
- new economizer banks. TRADE SECRET DATA ENDS]
- Remove and not replace the small FGR economizers, pending confirmation that the FGR fan is compatible with the 750°F +20°F flue gas temperatures.
- The FGR intake "doghouses" will be lowered and redesigned with the addition of new support trusses.

The convection pass modifications recommended above are predicted to achieve an EEGT at full load (3,638,000 lbs/hr main steam flow) dirty condition of 733°F. At minimum load (1,627,000 lbs/hr main steam flow) clean, the achievable EEGT is predicted to be 635°F. These recommended modifications not only achieve the target EEGT range, but are also expected to attain desired superheat and reheat steam outlet temperatures. For the conceptual design, the costs for the modifications described above and shown in Appendix F were included in the capital cost estimate.

3.2.3 Boiler Reinforcement

The Big Stone AQCS project has various emission control options are under consideration that will add equipment to the flue gas path downstream of the boiler. The new emission control equipment will increase the system pressure drop and new ID fans will be used to provide the additional draft capacity needed to compensate for the pressure drop. The existing fans are capable of approximately 30" WG of static head, while the new fans will be capable of nearly double this amount. With such a large increase in ID fan capability, both the steady-state and transient pressures can increase to the level that the boiler, baghouse, and/or ducts are at risk of being imploded. A study of the risk of implosion was performed. The report from the study is provided in Appendix C.

The furnace section of the boiler has a steady-state deign pressure of +3"/-7" WG, but the transient pressure design of the furnace is unknown. Similarly, the economizer section of the boiler has a steady-state design pressure of -23" WG, but the transient pressure design limit of the furnace economizer section is unknown. The Big Stone furnace has experienced a master fuel trip (MFT) transient that exceeded -10" WG, and new larger ID fans will have the capability to generate transients with a greater magnitude than created by the current ID fans.

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As part of the evaluation, it was determined that the boiler would probably not have sufficient strength to withstand a future MFT event. Therefore, reinforcement of the boiler to withstand a reasonable negative pressure spike is recommended to minimize the risk of implosion. The furnace should be reinforced to withstand a transient of at least , the economizer to , and the air heater to . Other parts of the existing flue gas path would also require reinforcement to withstand a reasonable negative pressure, though many of these are being replaced with new duct.

Boiler manufacturers typically recommend reinforcing the furnace to WG, but insurance companies do not typically require furnace reinforcement to WG. Furnace reinforcement to WG is reasonable and the amount of reinforcement required can be minimized by using VFDs, for example, to help reduce the pressure transient. Insurance carriers have agreed with this level of protection on past projects. OTP should approach the insurance carrier with this proposed level of protection.

Based on the recommendation to reinforce the furnace to at least WG, NFPA 85 evaluations and studies of other similar boilers, and input from , the estimated budgetary capital costs and schedule for boiler reinforcement to WG are included in the capital cost estimate.

An estimated budgetary capital cost for furnace reinforcement to WG is not available without a more detailed study by the original boiler supplier ( ). However, the cost is expected to be significantly higher since furnace reinforcement to WG is expected to require buckstay replacement, roof support modifications, and windbox modifications. TRADE SECRET DATA ENDS]

A review of the proposed flue gas system hardware changes, software changes, control methodology, and conclusions in the report provided in Appendix C by the Authority Having Jurisdiction (AHJ), which is Factory Mutual (FM), is still required.

3.3 SCR REACTOR AND CATALYST

3.3.1 Design Summary

Table 3-1 identifies the major design parameters for the SCR reactor and catalyst.

Table 3-1. SCR Reactor Design Summary

Parameter	Performance
Volumetric flue gas flow	3,350,000 acfm
Inlet NO_X rate, average	0.80 lbs/MBtu
Design catalyst inlet velocity	16.5 ft/s
Economizer outlet temperature (full load)	750 (±20°F)
Economizer outlet temperature (low load)	625 ±20°F
SCR SO_2-to-SO_3 oxidation	2.0% [TRADE SECRET DATA BEGINS
NH_3 slip, maximum at end of catalyst life	
Design removal efficiency	
Number of catalyst layers per reactor	
Catalyst modules per layer	
Catalyst volume per layer	
Reactor	
Inlet riser	
Sootblower	
Sonic horns	TRADE SECRET DATA ENDS]
SCR hopper on outlet	Space allocated; need will be determined in detailed design

3.3.2 SCR Reactor [TRADE SECRET DATA BEGINS

Big Stone will have SCR reactors. The unit has air heaters; therefore, having reactor per air heater will ensure the best possible flow balance.

The cross-sectional area of the SCR reactor is set by the design volume of gas and the target catalyst inlet velocity and is not dependent on the inlet NO_X concentration. The design criterion for gas volume is 3,350,000 acfm at the economizer outlet and the target velocity at the catalyst inlet is a maximum of 18 ft/s. Although it would be ideal to have a square SCR reactor, the length-to-width ratio is determined by the physical dimensions of the catalyst modules that comprise each catalyst layer. Module sizes offered by SCR catalyst vendors are standardized to provide flexibility to utilities in choosing from a variety of catalyst vendors instead of being restricted to the initial catalyst supplier. They are approximately 950 mm in width and 1,900 mm in length. The design reactor cross-sectional area must also include space for the support steel needed to accommodate the catalyst layer. Because the reactor width and length are set by the physical design of the catalyst and support, the velocity at the catalyst inlet must be calculated from a proposed reactor configuration. Several iterations were performed to determine a configuration that meets the velocity criteria established.

The reactor height is set by the number of catalyst layers required, which is determined by the overall catalyst volume required to achieve the NO_X reduction guaranteed. The reactor will have levels for catalyst. The first layers initially will be supplied by the SCR vendor, and the layer will be a spare layer that will be loaded after approximately 16,000 hours of operation. Similar to the cross-sectional area dimensions of the reactor, the catalyst layer heights are bound by the height of the catalyst elements. The module heights will be limited to 5.5 feet to ensure that Big Stone will have the flexibility to load any catalyst supplier's modules. The SCR will be expected to operate within an 8" to 10" w.c. pressure drop range (large-particle ash [LPA] screen through SCR exit duct). TRADE SECRET DATA ENDS]

The SCR reactor will have an inlet and outlet sampling grid to measure the NO_X and NH_3 distributions at the SCR inlet and outlet. At a given location along the width of the reactor at the outlet, a bundle of sampling tubes is inserted and flanged to the reactor. Each tube in a bundle has different lengths that extend varying distances through the reactor. Several tube bundles are installed at the outlet in an arrangement that allows a "grid" to be formed of sampling locations. This sampling grid will be used to tune the ammonia injection grid (AIG) to optimize the NO_X/NH_3 distributions at the reactor outlet. The sampling grid at the outlet will also be used during performance testing to demonstrate that the Contractor's design meets the guaranteed performance. It is not expected to be used for continuous monitoring of the SCR.

3.3.3 Large-Particle Ash Screen

Most PRB coals produce large agglomerations of fly ash termed *popcorn ash*. Popcorn ash can have an impact on SCR performance if not removed before the catalyst. It can plug the openings in the catalyst and render those sections of catalyst ineffective for NO_X reduction.

The method most widely used to remove the popcorn ash has been the installation of a screen. This typically is a perforated plate coated with erosion-resistant material or thick wire screen, also coated with erosion-resistant material. However, based on the industry experience, the average velocity through the open area of the screen should not exceed 45-50 ft/sec. Installations, with 70-ft/sec or higher average velocity, have experienced severe erosion problems. Typical pressure drop across the screen (with 50-60% open screen) will be in the range of 0.5-0.75 inches w.c. The plugging of the screen can be detected by monitoring the pressure drop across the screen.

3.3.4 Internal Online Cleaning [TRADE SECRET DATA BEGINS

The sootblowers required for cleaning the catalyst beds typically use steam and are of the rake-type design. They would be located approximately 18-20 inches above the layer of catalyst and would be situated such that when fully retracted (approximately 6.5 feet), they provide access to the catalyst without requiring sootblower removal. The steam cleaning medium has a supply pressure of 35-60 psi, and superheat of 50°F. Typically, the total amount of sootblowing steam required for SCR systems is 40-50 lbs/hr of steam per megawatt. The sootblowers are not used continuously rather once per shift or once a day during initial operation and as required based on experience. The sootblower controls are typically programmable logic controller (PLC)-based with an operator interface in the main control room however can be integrated to the distributed control system (DCS) if required.
TRADE SECRET DATA ENDS]

A large number of high-dust SCR systems are retrofitted with air-powered sonic horns at each catalyst elevation to allow the removal of accumulated fly ash. Sonic horns have the advantage of eliminating the potential addition of moisture to the SCR system and operate at much lower power requirements than steam sootblowers. Sonic horns are recommended because of their lower installed cost and successful applications at similar installations. Due to

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excessive ash buildup due to PRB coal ash characteristics, installation of sootblowers on the layer of the catalyst is recommended. TRADE SECRET DATA ENDS]

3.3.5 Catalyst

Catalyst formulation and type are the two primary design issues that need to be evaluated before selecting a catalyst. Catalyst formulation involves the selection of elements used to avoid the damaging effects of flue gas and ash constituents, as well as to provide operational stability in various temperatures. The coals and operating conditions at Big Stone do not require a unique catalyst formulation that would significantly affect the cost of the catalyst. However, significant boiler upgrade cost is being incurred to create a temperature range at the SCR inlet to allow conventional materials to be used.

The types of catalyst available include plate, corrugated, and honeycomb. The plate-type catalyst consists of a catalyst coating over a metal plate or wire mesh. The corrugated-type catalyst consists of catalyst coating over a fiberglass substrate. The honeycomb catalyst is manufactured as a homogeneous or coated catalyst. The homogeneous catalyst manufacturing process involves the mixing of titanium oxide (TiO_2) and vanadium oxide (V_2O_5) and extruding the mixture using a dye. The honeycomb catalyst, especially the extruded type, has a larger amount of catalyst per volume than the plate-type. The corrugated-type catalyst is a design variation of the honeycomb catalyst. This type of catalyst design reduces costs and space requirements of the reactor. However, the plate-type catalyst is more resistant to plugging because of its resistance to fly ash erosion and is more easily cleaned. Any of the three types of catalyst could be used at Big Stone and typically, the catalyst volume will not change based on the type of catalyst chosen. Recommendation on a specific type of catalyst will be made in detail engineering.

3.3.6 SCR Access and Catalyst Replacement [TRADE SECRET DATA BEGINS

The catalyst replacement features typically include either one or two doors and a trolley system or grating to move the catalyst into the reactor. Based on a previous time-motion study performed by S&L, it was determined that using a pallet truck to move the catalyst in the reactor offers the best approach to change-out catalyst and grating is used to support the catalyst and allow the pallet truck to move freely. The large reactor volume required at Big Stone will require doors at each catalyst level to move the catalyst in and out of reactor.
TRADE SECRET DATA ENDS]

Access to each layer of catalyst would be provided on one side of each reactor. The access doors would be at least four feet wide and seven feet tall and will be used to replace catalyst beds. Catalyst modules will be lifted from grade using an air-tugger or electric hoist and placed on the working elevation or directly onto a waiting pallet truck. Permanent gallery will be specified internal to the reactor such that pallet trucks can be moved inside through the loading doors to place the modules in position and remove them during replacement. No overhead trolleys or rails are necessary for loading of the catalyst modules inside the reactor.

The sootblowers would not have to be removed during catalyst replacement in that adequate access will be available by fully retracting the sootblowers during the replacement process. The sonic horns will also not interfere with catalyst replacement.

Access galleries will be provided at each catalyst level, at the AIG, at the sootblowers, and at the measurement grids. Smaller access doors would also be provided at each catalyst layer to allow for inspections and catalyst sampling.

3.4 SCR REAGENT SUPPLY

3.4.1 Description [TRADE SECRET DATA BEGINS

S&L conducted a study of ammonia delivery systems (report SL-010364 provided in Appendix E) that compared anhydrous ammonia, 19% aqueous ammonia, 29% aqueous ammonia and urea. The study concluded that the most cost-effective reagent to use for the SCR was anhydrous ammonia; however, it considered to highly hazardous by the Occupational Safety and Health Administration (OSHA) and is subject to the most stringent regulatory requirements. Consideration for plant personnel and public safety must be given in the final decision-making process. Note that the study assumed an inlet NO_X of 0.80 lbs/MBtu. The study (see Appendix F) shows that the installation of SOFA would reduce the NO_X at the inlet of the SCR to approximately NO_X. This will significantly reduce the amount of anhydrous ammonia injected and thereby reduce the O&M costs. During detail engineering, the impact of this lower inlet NO_X will be reviewed. TRADE SECRET DATA ENDS]

3.4.2 Design Summary

Table 3-2 identifies the major design parameters for the Big Stone anhydrous ammonia system. Note that the conceptual design and capital cost estimate of the anhydrous ammonia system include the use of vaporizers. The industry is starting to consider direct injection (elimination of the vaporizers) of anhydrous ammonia and this concept will be reviewed further in detail engineering. This would again favor the use of anhydrous ammonias the reagent of choice.

Table 3-2. Anhydrous Ammonia Design Summary

Parameter	Performance
Design ammonia feed rate	1,573 lbs/hr
Inlet NO_X rate, average	0.80 lbs/MBtu
NO and NO_2 distribution	95% NO/5%NO_2
Ammonia storage	[TRADE SECRET DATA BEGINS
Storage capacity	
Number of tanks	
Vaporization skid	
Pump skid	
Dilution air skid	
Number of anhydrous ammonia trucks/week	TRADE SECRET DATA ENDS]
Injection location	Ammonia injection grid located in SCR riser ductwork
Safety features	Portable eye wash station, shower and deluge near ammonia tanks, portable eyewash station near AIG

3.4.3 Ammonia Injection Grid

Ammonia would be distributed through an AIG. There are two types of AIG designs used in SCR technology - a multiple-zone tunable grid design and lances/injectors followed by static mixers.

The multiple-zone design includes hundreds of nozzles and valves that allow control of ammonia in an X x Y array such that the ammonia flow rate can be controlled to each zone to produce a uniform NO_X concentration at the catalyst outlet. This type of design had been used in SCR systems installed in Japan and Europe in the early 1980s to achieve 70-80% NO_X removal efficiency. The tunable-type of system is not usually used in U.S. installations, as utilities in the U.S. rely on a longer SCR inlet duct, injection lances, and static mixers to provide a uniform ammonia feed to the catalyst. The tunable-type system could be used when the inlet to the SCR is shorter.

Most SCR installations in the U.S. rely on static mixers to provide uniform distribution of the ammonia at the inlet of the first catalyst layer. After the flue gas is taken from the economizer, a long duct section is used to house the AIG and static mixers. The injection lances provide some uniformity of ammonia injection across the duct, but the static mixers closely follow and they mix the ammonia and flue gas so a uniform mixture reaches the catalyst. The SCR duct, mixers, and reactor are modeled using a physical model and the uniformity of ammonia distribution is verified. For high-efficiency SCR designs, static mixers with ammonia injectors or lances described above have been widely used. Utility installations have achieved 90% NO_X reduction with this approach.

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The conceptual design of the SCR systems at Big Stone has the AIG located approximately five feet after the last transition in the ductwork. This ensures that a proper flow pattern has developed prior to the ammonia being injected. The static mixers are located approximately 12 feet after the AIG. Static mixers are installed to achieve a uniform NO_X/NH_3 ratio and velocity distribution before entering the catalyst. It is generally recommended to include to hydraulic diameters between the AIG and the catalyst face to ensure sufficient mixing.

TRADE SECRET DATA ENDS]

3.5 FGD ABSORBERS

3.5.1 Description

S&L conducted a screening study SO_2 technology (wet vs. dry) that concluded dry FGD to be the optimal choice for Big Stone. Results of that screening study are included in Appendix B (SL-010303).

[TRADE SECRET DATA BEGINS

Big Stone Plant will have SDAs, with each absorber treating of the flue gas. The SDAs will be 62 feet in diameter. The absorber will be a vertical open-chamber, with cross-current contact between the lime slurry and flue gas. The SDAs will be constructed of carbon steel since the PRB coal fired at Big Stone does not pose a significant concern for chloride or SO_3 corrosion. Some utilities in the eastern U.S. have applied alloy wallpaper or a spray coat for corrosion protection. These measures are not included in this conceptual design. Each SDA will also have atomizers. The conceptual design of the Big Stone SDA includes atomizers per SDA. The number of atomizers varies between vendors; however, for the conceptual study, S&L used the more conservative design. Slurry atomization is the key performance criterion in reducing SO_2 from the flue gas. Slurry is introduced to each

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absorber as a fine mist of droplets. This fine mist of droplets creates a large surface area in which the flue gas can mix. Atomizers, either rotary or dual-fluid, produce the fine droplets needed for effective SO_2 removal in a spray dryer system. The conceptual design is based on a rotary atomizer in the SDA. The SDA will be expected to operate within at about 6" w.c. pressure drop. Duct to and from will add some more pressure drop.

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absorbers will share a common penthouse for weather protection during maintenance activities on the atomizers. A spare atomizer will also be stored or will stand in the penthouse of each SDA. The penthouse will have a vacuum system to clean the area. Also, service water for hose stations will be provided to clean some areas that are susceptible to slurry spills. A drain to grade and a sump at grade to accumulate the washdown will be needed in these areas. The penthouse will require heating and ventilation. The penthouse walls will have two inches of insulation but no interior metal lagging. Additionally, insulation typically is not lagged on the interior of buildings. If the insulation becomes damaged, it would be visible to plant personnel and therefore should be repaired. There will be a jib crane and hoist, common to both SDAs, in the penthouse to raise and lower equipment and tools from grade. Also, a new elevator is included in the conceptual design located near the SDAs for personnel and maintenance access. A minimal amount of solids will fall out in the SDA hopper, and will have to be shoveled out. A new Dumpster is included in the conceptual cost estimate to collect these solids.

TRADE SECRET DATA ENDS]

3.5.2 Design Summary

Table 3-3 identifies the major design parameters for the Big Stone FGD absorbers.

Table 3-3. FGD Absorber Design Summary

Parameter	Performance
Volumetric flue gas flow	2,427,000 acfm
Inlet temperature	325°F
Inlet SO_2, average	0.92 lbs/MBtu [TRADE SECRET DATA BEGINS
Outlet SO_2	
Approach to adiabatic saturation	30°F
Number of SDAs	
Diameter of each SDA	
Number of rotary atomizers per SDA	TRADE SECRET DATA ENDS]
SDA residence time	Minimum of 10 seconds

3.6 PULSE-JET BAGHOUSE

3.6.1 Description

S&L's screening study (Appendix B, SL-010303) evaluated whether the existing baghouse could be reused. The existing baghouse at Big Stone is 37 years old and most baghouses and ESPs are typically replaced after 30-40 years. Per the screening evaluation, it was determined that the increase in negative pressure on the existing baghouse and ductwork will require extensive reinforcement from the addition of SO_2 and NO_X reduction AQCS technology.

The existing baghouse is designed to handle a continuous operating pressure of up to negative 25 inches w.c. and OTP currently operates the baghouse at approximately negative 28 inches w.c. For dry FGD technology, implementing an SDA could add up to 7-10 inches w.c. of additional negative pressure before the flue gas enters the baghouse. Installation of SCR will add even more negative pressure ahead of the baghouse (approximately 8-10 inches w.c.). The existing baghouse and ductwork remaining in place will be unable to handle the additional negative pressure. In addition, the existing baghouse fly ash handling system will also need major modifications due to the increased solid loading with an SDA. The screening study determined that it was more cost-effective to install a new baghouse than take risk in modifying the existing baghouse. Therefore, the conceptual design and cost-estimate includes a new baghouse.

[TRADE SECRET DATA BEGINS

The new baghouse will reduce emissions to less than of filterable particulate matter (PM). The opacity will be less than on a six-minute average. In addition to PM and opacity, the baghouse also removes of the overall SO_2 removed in the system due to the layer of sorbent on the surface of the bags and the intimate contact as gas passes through the cake. The baghouse is sized using a gross air-to-cloth ratio of 3.6 fpm. There is a spare compartment per casing, which allows the unit to operate with these compartments off line for maintenance. The baghouse will be expected to operate within a 6" to 8" w.c. pressure drop range (flange-to-flange) with all the compartments in service.

The collected solids will be removed from the baghouse hoppers with a pressurized material handling system. A vacuum pneumatic conveying system will be installed that requires 14' of clearance between the hopper room floor and the hopper outlet flange. The material handling system will be suspended from the hoppers to allow the material handling system to expand at the same temperature as the casing. There will be some solids that fall out in the hopper enclosure when the unit is off line and as hopper doors are opened, but this should be minimal. Dry deposits would be vacuumed up as part of house cleaning, but service water is also provided to wash down the area if needed.

Hoppers will have sledge plates, vibrators, and poke holes to keep the solids flowing in the hopper. These accessories will be accessed from grade and a hopper platform is not included. Hopper heaters will keep the lower third of the hopper warm and free from condensation. Additionally, the hopper is covered with of insulation, which is removable so the heaters can be changed-out without harm to the insulation.

The bags will be cleaned with dry and oil-free compressed air. blower and dryer trains will supply air to the penthouse of each of the casings. The blowers will be air-cooled and will have an inlet air duct from the outside of the enclosure. blower train will be located in the hopper enclosure area of each baghouse casing and there will be a crossover pipe between casings tying the systems together. Receivers to store the air will be included. These air systems will be sized to deliver the bag cleaning air, the motive air for the baghouse dampers, air for the ACI silo fluidization, control air for the material handling system in the hopper enclosure, and other

TRADE SECRET DATA ENDS]

miscellaneous systems. It is recommended that separate air receivers be used for the cleaning air and the damper air. This will ensure that air is available to operate the dampers if power is lost to the plant.
[TRADE SECRET DATA BEGINS

The baghouse plenum will either be a top-door-type or a walk-in plenum-type. The top-door design will allow staff to remove the door and step down onto the tube sheet for maintenance. A hoist system is provided to allow the large compartment door to be removed for access. A vacuum break is needed on each compartment to allow easy removal of the door. The walk-in plenum design will allow access to the tube sheet by access doors (x). The area above the tube sheet is a confined space and needs ventilation and special precautions. The advantage of the walk-in plenum is that air in leakage is minimized because the doors are smaller and can be tightly shut to seal air out. In comparison, the top-door design has a large perimeter of gasket that is difficult to keep in top condition, and allows in-leakage. Both designs work successfully after a dry FGD. TRADE SECRET DATA ENDS]

A penthouse will protect from elements of weather. Heat and ventilation will be included to control temperature to 10°F above ambient temperature or 55°F, whichever is greater. The outlet and bypass dampers operators will be accessible within the penthouse, as well as the bag-cleaning air-pulsing header. A jib crane and hoist by the original equipment manufacturer (OEM) will enable boxes of bags, cages, or tool-boxes to be lifted to the penthouse and to lower pneumatic operators to grade.

Utility baghouses have inlet and outlet dampers for each baghouse compartment, which will allow for a compartment to be taken off line and for plant staff to enter the compartment to check for bag leaks. The ducts and compartments are all normally under negative pressure so the typical utility design allows safe entry into the compartments.

3.6.2 Design Summary

Table 3-4 identifies the major design parameters for the Big Stone pulse-jet baghouses.

Table 3-4. Pulse-Jet Baghouse Design Summary

Parameter	Performance
Volumetric flue gas flow	2,141,000 acfm
Particulate load	231,000 lbs/hr
Inlet temperature	167°F
Casings	[TRADE SECRET DATA BEGINS
Compartments per casing	
Baghouse footprint	
Number of bags	
Air-to-cloth with all compartments on line	3.60
Air-to-cloth with one compartment off line per casing	4.10
Bag length	
Bag material	PPS
Size and velocity of inlet plenum	
	Velocity = 3,600 fpm
Size and velocity of outlet plenum	18' x18'
	Velocity = 3,600 fpm
Number of hoppers	
Insulation	TRADE SECRET DATA ENDS]

3.7 LIME RECEIVING AND PREPARATION

3.7.1 Description [TRADE SECRET DATA BEGINS

The conceptual design is based on lime being delivered to Big Stone via truck. The plant will have lime silo with bin vent filters for dust control when it is being filled. The silos will be adjacent to the unloading area. The trucks will have on-board blowers that will pneumatically convey lime to the long-term storage silo. One lime truck will be unloaded in approximately 1-2 hours. If the silo design calls for a taller silo or faster unloading is needed, a

TRADE SECRET DATA ENDS]

stationary truck unloader can be added. Rail deliveries could also be studied further to allow for lower lime cost. However, rail deliveries would require significantly more capital cost for rail spurs and equipment.

Lime will gravity-feed from the silo hopper into the slakers in the reagent preparation building. The slakers can either be the ball mill- or detention-type. The primary function of the slaker is to hydrate the dry pebble lime into a slurry and create fine particles of $Ca(OH)_2$. The hydrated form of lime is the most reactive form and is necessary for high levels of SO_2 removal. The slurry from the slakers will discharge through grit screens into lime slurry storage tanks and will be agitated until needed for injection into the SDA. This system can also provide slurry to the existing cold-lime softener (CLS) so that the lime storage and slurry system there can be eliminated. Costs for demolition of the existing lime storage and slurry system have not been included in the estimate.

Removing grit is very important in the dry FGD process because it can plug the atomizer nozzles. Each slaker will have an external classifier or grit removal screen, whose main function is to separate large oversized grit and impurities from the slurry solution. Eventually, the oversized grit will be rejected from the system. The grit will be placed in Dumpsters and eventually hauled away. With the design coal and high-quality lime, a Dumpster should be adequate, but in some instances Dumpsters may not be sufficient to handle the volumes, and a grit pit might be needed. A front-end loader would be used to scoop and place the grit in a truck for disposal. The conceptual design is based on detention slakers, which would have piles of grit dumped to grade that would then need to be hauled off to disposal each day.

3.7.2 Design Summary

Table 3-5 identifies the major design parameters for the Big Stone lime receiving and preparation system.

Table 3-5. Lime Receiving and Preparation Design Summary

Parameter	Performance
Lime silo storage	[TRADE SECRET DATA BEGINS
Lime silo capacity	
Pebble lime quality	90% CaO minimum
	¾" x 0" lump size
Fresh lime feed	
Slaker	
Lime slurry storage tank	
Lime slurry transfer pumps	
Lime slurry, wt% solids	20%
Makeup water tank (use in recycle system)	
Slurry sump basin	
Slurry makeup water tank (use in slaker)	
Slaker water requirement	76 gpm
Slaking temperature requirement	170°F minimum
Number of lime trucks/week	17
Lime preparation building	TRADE SECRET DATA ENDS]

3.8 RECYCLE SOLIDS PREPARATION

3.8.1 Description

The recycle slurry is recycled to the SDAs to reduce lime consumption. There is residual activity and alkalinity left in the lime after it has been passed through the system once; therefore, it is re-introduced to gain additional lime utilization. Also, a droplet of ash and lime mixture dries faster than a droplet of lime alone. This will reduce the time required to dry the slurry in the absorber and also prevent localized lime droplets coming in contact with the SDA walls.

Waste solids will be collected in the new pulse-jet baghouse. The solids will be transported to either the recycle silo or to the waste silo. The system will be controlled to send ash to the dry FGD recycle silo until full, and then to send the waste to the waste silo until the recycle silo needs more waste. Solids primarily will be sent to the recycle silo, but about 25% of the time will be sent to the waste silo.

The recycle system is located in its own building. A portion of the waste solids from the baghouse will be sent to a recycle silo located within this building. The dry waste from this silo flows to a premix tank, where it is combined with water. The slurry overflows to a recycle holding tank, which then overflows into a recycle slurry storage tank. Mixing in the premix tank is difficult due to a dry, dusty waste being mixed with water. The material in the premix tank has the consistency of a paste-like material and, therefore, requires more maintenance than other parts of the system. This recycle system allows the lime to be passed through the SDA several times, which allows each particle of lime to be utilized more. Thus, the lime particles that did not absorb SO_2 the first time through the system have the chance to do so several more times. The dry FGD recycle system will require significant maintenance because mixing a dry powder with water is more troublesome than slaking lime. The recycle premix tank, if not agitated continuously, can set up to the consistency of concrete and require a jackhammer in order to clean out.

3.8.2 Design Summary

Table 3-6 identifies the major design parameters for the Big Stone recycle lime receiving and preparation system.

Table 3-6. Lime Receiving and Preparation Design Summary

Parameter	Performance
	[TRADE SECRET DATA BEGINS
Recycle silo storage	
Recycle slurry mix tank	
Recycle slurry storage tank	
Recycle slurry pumps	
Recycle slurry, wt% solids	40%
Makeup water requirement	556 gpm
Solids to recycle silo	196,000 lbs/hr
Recycle building	TRADE SECRET DATA ENDS]

3.9 SOLID WASTE HANDLING

3.9.1 Description [TRADE SECRET DATA BEGINS

The dry FGD process adds several times more solids to the inlet of the baghouse, and these solids must be transported to either the recycle or the waste silo. The new solid waste handling system will collect waste from the hoppers in the new baghouses. The waste will be pneumatically conveyed from the baghouse hoppers to either the existing ash silo or the new waste silo. Both silos will be used. silo will have bin vent filter. The existing silo bin vent filter is not large enough for the increased waste that will be sent to it; therefore a new bin vent filter is included. Since one silo will be operated at any given time, the redundancy requirement for the bin vent filter has been built in. TRADE SECRET DATA ENDS]

Detailed information on the ash handling system and solid waste disposal is provided in Appendix M (SL-010402). In addition, the report identified the most cost-effective method to transport the ash to the existing landfill. A new landfill will not be required as there is sufficient capacity in the existing landfill. The study recommended transport of the waste by truck with the ejector feature. However, OTP would prefer using scrapers in lieu of the trucks since this is the current practice at Big Stone.

3.9.2 Design Summary

Table 3-7 identifies the major design parameters for the Big Stone solid waste handling system.

Table 3-7. Solid Waste Handling Design Summary

Parameter	Performance
Coal, HHV	8,200 Btu/lb
Ash content	6%
Bottom to fly ash split	50/50
Distance from baghouse to fly ash silos	[TRADE SECRET DATA BEGINS
Ash piping	
Total solids to hoppers	231,000 lbs/hr
Solids to storage silos	35,000 lbs/hr
Fly ash transport rate	Two times the make rate TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS

Parameter	Performance
Dry ash density	45 lbs/ft^3
Ash Haul Equipment	
Bin vent filters (one per silo)	
Waste storage silo	
Waste blower building	TRADE SECRET DATA ENDS]

3.10 ACI SYSTEM FOR MERCURY REDUCTION

3.10.1 Description

[TRADE SECRET DATA BEGINS

An ACI system will be provided that is designed for mercury removal. Appendix L provides details on the mercury control evaluation (SL-010393). For the ACI efficiency, the SO_3 needs to be at or less where the carbon is injected. Since Big Stone burns PRB, staying below the level will not be an issue. Also, experience has shown that with PRB fuels, halogenated powder-activated carbon (PAC) is more effective than non-halogenated PAC.

The carbon is injected prior to the SDA. Injecting before the SDA helps to oxidize some of the elemental mercury to oxidized mercury since the chlorides have not been removed yet. Injecting before the spray dryer also increases the residence time for the carbon to react with the mercury. However, the greatest amount of mercury is removed in the baghouse. The carbon uniformly accumulates on the bags in the baghouse and creates a cake with the fly ash. The flue gas gets pulled through the carbon accumulation and this is where the majority of the mercury is removed.

The GA drawing in Appendix A shows the ACI silo located directly south of the boiler building and west of the SDAs. This location reduces the length of piping needed to the injection location. The silo will be filled by trucks, which will pull up next to the silo and use their onboard blowers to unload the carbon into the silo. The truck's driver will have a control panel that connects to the operating room. Operators will send a signal alerting the truck driver to fill the silo. As trucks carry about 40,000 lbs of carbon, the silo will hold about truck loads of carbon and the plant will need about truck delivery per week. TRADE SECRET DATA ENDS]

3.10.2 Design Summary

Table 3-8 identifies the major design parameters for the Big Stone ACI system.

[TRADE SECRET DATA BEGINS

Table 3-8. ACI Design Summary

Parameter	Performance
Design injection rate	which is 5 lbs/mmacf halogenated PAC
Expected Injection rate	lbs/hr which is 2 lbs/mmacf halogenated PAC
Number of silos	
Silo size	
Silo storage quantity	
ACI electrical building	
Injection trains	
Safety features	Portable eye was station in base of silo
	Grating on top of silo, but no enclosure
Injection location	At least 60', 1 second prior to the SDA
Piping	
Level detectors	One radar detector to measure carbon level

TRADE SECRET DATA ENDS]

3.11 ID FANS

3.11.1 Description

The new SCR and dry FGD equipment and the new interconnecting ductwork will add pressure drop to the Big Stone flue gas draft system. The existing ID fans do not have the capability of pulling the additional draft necessary; therefore, the fans will be removed from service and new replacement fans will be installed after the new baghouse to handle the entire flue gas path. The replacement fans would be designed to overcome the draft loss of the boiler, SCR, air heater, SDA, baghouse and ductwork/dampers. Appendix G provides details on fan design alternatives (SL-010396). Two fan arrangements and two fan technologies were evaluated:

[TRADE SECRET DATA BEGINS

- centrifugal fans with variable-frequency drive (VFD).
- centrifugal fans with VFDs or axial fans with variable-pitch blades.

Inlet dampers and variable inlet vane flow controls were not considered with the centrifugal fans due to their rapid fall-off in operating efficiency when volume flows are reduced below 85% of the normal full load flow. The results of the study concluded that OTP should install centrifugal fans with VFDs based on installation, operating and maintenance advantages. TRADE SECRET DATA ENDS]

3.11.2 Design Summary

Table 3-9 identifies the major design parameters for the Big Stone ID fans.

Table 3-9. ID Fan Design Summary

Parameter	Performance
Percent of total flow per fan	[TRADE SECRET DATA BEGINS
Number of fans	TRADE SECRET DATA ENDS]
Fan type	Centrifugal with variable frequency drives
Test block condition:	
Flow	2,052,000 acfm
Static pressure	50" w.g. (static rise for test block flow plus 10%)
Motor size	12,000 horsepower (hp)

3.12 DUCTWORK

3.12.1 Description

The ductwork system is generally categorized in two ways – hot-side and cold-side, based on the location in the flue gas route and the operating temperature to which it is subjected. In addition to discussions of standard hot- and cold-side ductwork arrangements, the study also considered the use of SCR reactor boxes in relation to those arrangements, as discussed below.

3.12.1.1 Hot-Side Ductwork [TRADE SECRET DATA BEGINS

The first part of ductwork in the flue gas route is from economizer outlet to SCR reactor inlet and from the SCR reactor outlet to air heater inlet. This section consists of isolated parallel routes from each economizer to the SCR reactor and back to air heater. It is subjected to high operating temperature of about 750°F. As a result, material, which has a better strength under the elevated temperature than standard carbon steel, is typically utilized for the plates, stiffeners, and other internal structural elements, such as internal trusses, in the hot-side ductwork.

It is desirable from performance and economical standpoints for this section of duct to be as short as possible. Locating the SCR immediately west of boiler building will offer the shortest distance. The duct starts from the economizer outlet and travels horizontally straight west out of boiler building. Because the coal tripper room is running north-south at the west end of boiler building, the ducts to and from SCR would have to straddle vertically above and below the tripper room. Several air heater support steels on column row J2 and boiler building steels on column row K may have to be reconfigured to provide the necessary clearance to the new duct route. After exiting the boiler building, the ducts turn vertically and rise to the top of the SCR reactors. The ammonia injection grid (AIG) typically is located in the lower portion of this vertical duct. Downstream of the AIG, or levels of static mixers will provide for even mix and distribution of flue gas and ammonia injection over the cross-section of ducts. This is important in maximizing SCR performance when the flue gas passes through the catalyst in the reactors. In SCR outlet ducts, hoppers maybe installed at the horizontal runs if the ash drop-out is determined to be excessive. This section of ductwork will end at the existing expansion joints, just above the air heaters.

TRADE SECRET DATA ENDS]

3.12.1.2 Cold-Side Ductwork

The second part of ductwork includes the flue gas route from the air heater outlet to SDA inlet, from the SDA outlet to the baghouse inlet, from the baghouse outlet to the ID fan inlet, and from the ID fan outlet to the chimney breechings. The 300°F operating temperature of this section is much lower than the hot-side, and could drop to about 160°F after the SDA. Special care must be taken in controlling the flue gas temperature and maintaining good insulation to safeguard the risk of duct corrosion due to below-dew-point condensation. Carbon steel material is typically used in the cold-side ductwork.

[TRADE SECRET DATA BEGINS

It is recommended to run the existing air heater outlet ducts inside the forced draft (FD) fan enclosure in order to avoid modifying the enclosure structure. The tie-in for bringing the flue gas to the new SDA will then be west of FD fan enclosure. Ducts from two air heaters will first be joined together as a combined header running to the south and then split just before each SDA. SDA inlets typically rise vertically, depending on the requirements of SDA supplier. Since the SDA and baghouse are supplied by the same manufacturer and are close-coupled together physically, the SDA outlet and baghouse inlet duct could be a short, straight piece, designed and supplied as part of SDA with baghouse scope of work to ensure a performance guarantee. Exiting the baghouse, the baghouse outlet will drop vertically directly into ID fan inlet pant-legs. ID fans are located such that the ID fan outlets are aligned with the chimney breechings to avoid ductwork kinks. of the ID fan outlets, however, does have to loop around the backside of chimney in order to enter from the north breeching. TRADE SECRET DATA ENDS]

3.12.1.3 SCR Reactor Boxes

[TRADE SECRET DATA BEGINS

reactor boxes are elevated to the west of existing boiler building. Similar to hot-side ductwork, the reactor boxes are subjected to high temperature and the same pressure conditions. Therefore, the same material and design allowable and overstress considerations will apply. The major differences between the reactor box design and the standard duct are the weight of the catalyst and its required support scheme. Typically, a box consists of external skin and internal catalyst support frames. The external skin has plate girders at the bent line to carry the entire reactor loads to the surrounding support steel structure. Large collector beams will be used above the plate girders for the upper levels. Together, the collector beams and plate girders provide the supports to the internal catalyst support frame. Platework and internal stiffeners will finish up the remaining of skin construction. The internal catalyst support frame at each level typically consists of a number of W24 to W30 parallel beams spanning from one side of box to the other for supporting the catalyst modules. The beam spacing will match approximately to the length of catalyst modules. Gratings thick will be used on top of the internal frame at each catalyst level. This grating floor will allow for pallet-truck traffic during the catalyst replacement, thus, eliminating the need for trolleys and hoists and associated headroom at each level. Baffle plates will be provided at the edge of boxes and between the modules to guide the flue gas through the catalyst and to prevent ash accumulation in the corners. Often, baffle plates are also used under the catalyst support beams to mitigate flow turbulence.

TRADE SECRET DATA ENDS]

A hopper will be attached to the bottom of reactor box and will guide the exiting flue gas to the air heater inlet ducts. The hopper design will follow standard ductwork construction with stiffeners being located outside of duct plates.

3.12.2 Design Summary

The function of ductwork is to form a flue gas path from the boiler to the chimney. Unlike regular structural elements, which are typically subjected to ambient temperature only, the ductwork design must address the thermal effect, which includes the reduced material strength under the elevated temperature, thermal expansion and contraction, thermal friction forces, and creep rupture for progressive long-term deformation. Two levels of design temperatures should be considered, i.e., operating and excursion cases. Under the operating case, the ductwork should not exceed code-allowed stresses from both short-term yielding and long-term creep rupture perspectives. Under the excursion case, since this typically occurs in a relatively short duration before the creep rupture can develop, the long-term creep rupture effect does not need to be considered. Associated with elevated temperatures, the ductwork will have to be designed for the accompanying pressures. Different allowable stresses and overstress factors should be used for operating and excursion cases.
[TRADE SECRET DATA BEGINS

The entire ductwork system includes structural and non-structural elements. Structural elements should form a determinate system to avoid arching effects and the uncertainty of load distribution, especially under elevated temperatures. The elements typically consist of plate work, stiffeners, internal trusses, balancing struts, stub columns, sliding-plate assemblies, hold-down details, and lateral restraints. Structural elements are designed for bending and squashing effects, and for unbalanced forces due to internal pressure, self weight of duct, ash accumulation, and wind or seismic lateral transient forces. Typically, a truss will develop from the plates and stiffeners to carry the self weight, ash loads and wind or seismic forces to the supports. Non-structural elements include flow devices, turning vanes, splitter plates, dampers, expansion joints, access doors, and external insulations and laggings. TRADE SECRET DATA ENDS]

The duct route typically divides into to many segments separated by expansion joints. The size of each segment should be carefully selected to minimize the unbalanced forces and to facilitate fabrication and installation. In general, a single duct segment should not exceed 60-80' in length due to transportation limitations and construction crane size consideration.

3.13 CHIMNEY

Big Stone has a 498-foot-tall concrete chimney. The liner is made of carbon steel with the top 40 feet lined with stainless steel. With the addition of dry FGD, and operation of the flue at 30°F above saturation, the top one diameter of the inside of the liner needs to be coated to negate any potential impact of sulfurous acid condensation. Condensation can occur if cool ambient air is pulled down into the top of the liner under certain atmospheric conditions. However, because top one diameter of the Big Stone chimney is stainless steel, this coating will not be required and is not been included in the cost estimate.

3.14 WATER TREATMENT

3.14.1 Description [TRADE SECRET DATA BEGINS

Big Stone currently operates a brine concentrator (BC) to treat water from the cooling pond. The treated water is used in the Big Stone demineralizers and is sent to the ethanol facility. Due to high operating costs to run the BC, OTP requested S&L to review options for future operation of Big Stone without the BC. The installation of the dry FGD system could allow the BC to be taken out of service; however another treatment process would be needed to supply water to the demineralizers and . Appendix D (SL-010348) provides a summary report discussing all the options that were analyzed. The report identified that the most cost-effective solution for Big Stone is replacement of the BC with a new reverse osmosis (RO) system that would supply water to the Big Stone demineralizers only (Case 6). The facility would need to install additional RO system capacity and would have to obtain more water from the cooling pond and discharge more reject to the dry FGD system. A portion of the existing cold-lime softener (CLS) effluent will be the source of makeup for the new water treatment system. The treated water (permeate) will become the source of makeup to the existing Big Stone demineralizer and will also be used for lime slaking after blending with service water. The RO waste stream (reject) will be used as a source of makeup to the recycle solids dilution system. TRADE SECRET DATA ENDS]

The water treatment building is located in the area of the existing baghouse. The existing baghouse will have to be demolished in order to make room for this building. However, note that the water treatment system does not necessarily have to be operational when the dry FGD and SCR come on line. OTP could still rely on the BC and install the new water treatment system later.

3.14.2 Design Summary

Table 3-10 identifies the major design parameters for the Big Stone RO system.

Table 3-10. Reverse Osmosis Design Summary

Parameter	Performance
Feed to RO system	Existing CLS plant effluent [TRADE SECRET DATA BEGINS
Ultra filtration system	
Filtered water storage tank	
First-pass RO system, including booster pumps	
Second-pass RO system, including booster pumps	
Chemical dosing systems	
Control system	PLC
Water treatment building	TRADE SECRET DATA ENDS]
Treated water	300 gpm used as makeup to Big Stone demineralizer and dry FGD lime slaker (after blending with service water)
RO reject water plus ultra filtration backwash	50 gpm used as makeup to dry FGD recycle solids dilution system
Routing of treated water and waste streams	See interconnect diagram in Appendix Q

3.15 MECHANICAL BOP

Conceptual locations for process piping and piping extensions for interconnection with existing plant services are based on the arrangement of equipment illustrated on the GA drawings in Appendix A. An interconnect diagram displaying all the various air, water, steam, slurry, ammonia, etc., is provided as Appendix Q.

3.15.1 Pipe Racks and Corridors

The active ash and service water lines routed to the exiting fly ash silo will be relocated to facilitate construction of the new FGD system. The new lines will be located along the planned north-south pipe corridor separating the SDA modules and baghouse casings. During construction of the FGD system, a pipe rack will be installed along this corridor. This pipe rack will support the SDA lime and recycle slurry piping, baghouse-collected solid waste piping, FGD area steam heating piping, SCR ammonia piping, and service and instrument air pipe headers. FGD area service water and sump discharge lines will be located either underground along this same corridor or above ground supported on the pipe rack.

The FGD area pipe rack will extend to the SCR structural support steel. Ammonia supply piping for the SCR, steam piping to the FGD area, and a small lime slurry line to the CLS will be routed on this section of the pipe rack.

3.15.2 Air Supply System [TRADE SECRET DATA BEGINS

Each baghouse will be furnished with -capacity air-cooled compressors to provide baghouse cleaning air and the balance of instrument and service air to the FGD system equipment. An air receiver will be provided along with -capacity air dryers at each baghouse. Service and instrument air for the water treatment building and SCR will be extended from the existing station air systems. Air receivers will be located in the water treatment building and at the SCR reactors to accommodate short-term, peak air demand.
TRADE SECRET DATA ENDS]

The existing station compressed air system will be extended to provide service and instrument air to the SCR area and the new water treatment building. SCR sonic horns will require instrument air at about 70-80 psig.

3.15.3 Water Supply System

3.15.3.1 FGD Process Water

FGD system process water is required for lime slaking and lime slurry production, recycle solids slurry production, pump seals, and slurry line flushing. The source of process water for lime slaking, lime slurry production, and pump seals will be effluent from the BC or RO system permeate once the new water treatment system is operational.
[TRADE SECRET DATA BEGINS

There will be multiple sources for water for the production of recycle solids slurry. Initially, water from the blowdown holding pond and facility RO reject line will be routed separately to the recycle process water storage tank. Blowdown holding pond water will be routed through a new pipe connected to RW-9-APC
TRADE SECRET DATA ENDS]

located at the BC. It may be possible to use some or all of the existing, unused brine waste line routed between the sludge pond area and the fly ash silo.

Later, RO reject from the new Big Stone water treatment system will be routed to the recycle process water storage tank replacing the blowdown hold pond as the primary source of recycle process water. When the Big Stone unit is off line, RO reject will be routed to the BC sludge pond.

3.15.3.2 Service Water [TRADE SECRET DATA BEGINS

Service water to FGD area hose stations and pump seals will be provided through the relocated high-pressure service water line to the existing fly ash silo. This line, which originates in the vicinity of the north and south slag tanks, will be enlarged from to at the time of relocation to provide increased capacity for the new hose stations and new solid waste silo. TRADE SECRET DATA ENDS]

Service water to the water treatment building will be extended from an existing service water line in that area.

3.15.3.3 Domestic (Potable) Water

Domestic water for lavatory facilities and eyewash and safety shower stations located at the FGD system, ammonia storage area, and SCR ammonia vaporization skids will be extended from the existing station domestic water system.

3.15.4 Wastewater System

FGD area washdown and backflush wastewater, pump seal water, and miscellaneous drains will be collected in trenches and routed to sumps located at each SDA, in the lime slurry preparation building, and in the recycle ash preparation building. Sump pumps will transfer the wastewater to the slurry sump basin, where solids will settle out. Water in the slurry sump basin will be pumped back to the recycle process water storage tank. Periodically, solids will be removed from the slurry sump basin and hauled by truck to the dry waste disposal area.

3.15.5 Steam System [TRADE SECRET DATA BEGINS

Steam service will be provided for anhydrous ammonia vaporization, slaker and recycle solids slurry water preheating, sootblowers on the first layer of catalyst, and space heating for the FGD area process buildings and water treatment building. The source of steam will be the auxiliary steam header located in the vicinity of the auxiliary boiler.

3.15.6 Fire Protection

The existing underground fire protection header system will be extended to provide fire protection service to the FGD system and ACI silo and to the suppression spray water system at the anhydrous ammonia storage tanks.

3.15.7 SCR Ash Hopper Sluice System

Flow modeling may demonstrate that an ash hopper is required in the horizontal length of each SCR reactor outlet duct. If these hoppers are required, ash would be removed by extending the economizer sluice water supply piping to each hopper and returning the SCR ash hopper discharge sluice lines to the existing economizer ash discharge sluice lines. Isolation knife gate valves would be installed in each extended sluice water line and in each SCR ash hopper discharge sluice line. TRADE SECRET DATA ENDS]

3.16 CIVIL BOP

3.16.1 Description

Throughout the project construction, several civil features will be disturbed or will need to be reconfigured. Areas affected are not limited to the locations of final AQCS equipment. Civil scope should also cover construction laydown areas, trailers, contractor parking, ground assembling, staging, crane setting, etc.

The civil work would include construction sedimentation and erosion control; topsoil striping and rough grading; excavation and gravel surfacing; surface storm water drainage, including adding slopes, ditches, and culverts, oily water waste sewer and sanitary sewer installation; fence and gates; road work reconfiguration and surface pavement; and final grading.

3.16.2 Design Summary

3.16.2.1 Sedimentation and Erosion Control

A construction permit is typically required to outline the installation procedure and maintenance schedule for site protection. The program will span from the beginning of construction through completion.

3.16.2.2 Top-Soil Striping and Rough Grading [TRADE SECRET DATA BEGINS

Removal of to of top soil and vegetation and leveling of the areas to suitable elevation for the foundation installation and for construction activities such as trailers, contractor parking, laydown, ground assembling, staging and crane setting. This initial site work should also include laying down the gravel sub-base and base course of roadwork required to support the traffic and transportation of equipment during the construction.

TRADE SECRET DATA ENDS]

3.16.2.3 Surface Storm Water Drainage

The site is currently using a surface drainage system to dispose the storm water runoff. New storm water management should include proper surface slopes, ditches, and culverts across the roadwork for the construction and for the permanent operating.

3.16.2.4 Oily Water Waste Sewer and Sanitary Sewer Installation

Additional underground oily water waste sewers and man-holes must be installed to connect the new potential oil sources to the existing oil water separator. The potential oil sources include transformers, motors, and pumps where cooling oil or lube oil exists. A sanitary sewer should also be added to connect the new toilet facility to the existing sanitary discharge. Further study is required to identify the tie-in point of existing sanitary discharge, septic tank, or drain field.

3.16.2.5 Fence and Gates

Aside from final installation of permanent fence and gates, temporary fence and gates are required to define the construction zone, and isolate it from the plant operation area. Temporary fence and gates will also provide authorized access to the construction zone and safeguard the construction materials and equipment.

3.16.2.6 Road Work Reconfiguration and Pavement Surfacing

Throughout the construction, gravel road sub-base and base courses will need to be maintained. In the final stage, permanent roadwork will receive the surface asphalt pavement based on the new design configuration.

3.16.2.7 Final Site Grading

Prior to the completion of construction, the site must be re-graded to repair any damage caused by the construction. Typically, gravel will be added adjacent to the equipment installation and sod is applied on the balance of disturbed area outside of the loop road.

3.17 STRUCTURAL

3.17.1 Foundation

[TRADE SECRET DATA BEGINS

A soil investigation report was prepared for the original plant construction that concluded that either shallow mats or deep friction piles could be used for the main power block foundations, which have very substantial magnitude of load and are generally in the same area as the new AQCS equipment. The mat foundations have an ultimate bearing capacity of , while a group of forty-five -long piles could provide an ultimate bearing capacity of . Since the original plant design adopted the shallow foundation approach, a similar type of foundation will be suggested for the new AQCS equipment. Using shallow foundations also eliminates the risk of impacting the operating unit and the need of high head room typically associated with a pile installation. However, because the original soil investigation was focused on the different area, it is recommended that a new soil investigation program be developed specifically for the location and loads of the new AQCS equipment.

Preliminary assessment shows that using an ultimate bearing capacity of with a conservative factor of safety of , the shallow foundation approach is still a feasible scheme. This basic assumption is reflected in the budgetary cost estimate. The frost depth of about observed in the region must be reached for a shallow foundation construction to avoid frost heave. This thick concrete block will also provide large stiffness, thus reducing the differential settlement between the adjacent support points. TRADE SECRET DATA ENDS]

3.17.2 Support Steel

There are several support steel structures required for new AQCS project. Some of the steel structures will be under the equipment contractor scope of design and supply. This includes the SDA support steel and baghouse support steel. The balance of support steel and structures consists of a pipe rack connecting from the south of the existing baghouse to the existing ash silo; ductwork support steel from west of the boiler building to the SDA and from the baghouse to the ID fans and chimney breechings; SCR support steel; recycle ash and lime preparation building; and electrical cable rack connecting the main AQCS electrical building to various electrical buildings and AQCS equipment.

3.17.2.1 Pipe Rack and Electrical Cable Rack

The pipe rack will serve as the main artery for the routes of ash, slurry, water and air supply, lime slurry, electrical cable trays or conduits, and instrumentation and controls (I&C) interconnections between various AQCS equipment. It must be designed and installed to allow the existing ash pipe be rerouted on it, thus providing space for SDA construction. The pipe rack will have a minimum of 20' clear head room to allow ash, lime, and ammonia trucks to pass under. Multiple levels are expected to be needed to carry all the above piping and cables. Cable bus racks are required when there are no adjacent steel structures available. The width and size of cable racks are much smaller in comparison to the pipe rack.

3.17.2.2 Ductwork Support Steel

New support steel structures will be the concentrated, braced frame-type. Differential settlements at the duct support points must be minimized. Typically, tie beams are used to balance the thermal loads at the duct support level. Modification to the existing air heater and boiler building steels are required to provide the necessary clearance to ducts between the economizer and SCR system and between the SCR system and air heater. New vertical bracing members should also be added to span the tripper room over the removed columns. Because the existing structures will be significantly modified and altered, it is expected that the existing air heater and boiler building structures will need to be checked for current code compliance.

3.17.2.3 SCR Support Steel [TRADE SECRET DATA BEGINS

SCR support steel typically supports the reactors, inlet riser ducts, inlet horizontal ducts over the reactors, and the surrounding platforms for catalyst replacement. SCR support steel will also provide support for sonic horn, sootblower, and AIG access and O&M. Because the SCR reactors are situated high above the existing baghouse inlet ducts, a baseline approach is to erect two supporting tower outside of existing baghouse and allow the baghouse to continue to operate until the tie-in outage. A span space truss will be used to bridge over the supporting towers. A possible alternative would be to add columns in the middle of truss span. However, these internal columns will attract a significant amount of loads. The feasibility of constructing a suitably size foundation in the congested courtyard will have to be further studied in the detailed design stage. If adding internal columns is feasible, the truss span will be reduced by about half, thus decreasing the size of trusses and the tonnage of steel.

3.17.2.4 Recycle Ash Slurry and Lime Preparation Building

This building will support or house the recycle ash silo, premix tanks, slurry storage tanks, and associated pumps for processing the recycle ash, lime, and slurry.

Aside from several major steel structures mentioned above, cable bus supports from the unit auxiliary transformer (UAT) or reserve auxiliary transformer (RAT) to the main AQCS electrical building is assumed to be within the scope of work of cable bus supply contract.

3.17.3 Galleries

Several galleries are proposed for the AQCS project to provide access to areas for O&M. The galleries proposed are summarized below.

3.17.3.1 SCR Catalyst Platforms

The catalyst platforms are on the outboard side of SCR reactors. Hoist and trolleys are devices used to lift the new catalysts up to the change-out level and to lower the old catalysts down to trucks waiting on the ground. Once lifted to the change-out level, pallet trucks will move the catalyst to the reactor through the change-out doors located on the outboard face of reactors. To facilitate pallet-truck traffic, the entire platforms will be covered with gratings.
TRADE SECRET DATA ENDS]

3.17.3.2 SCR soot blower and sonic horn platforms [TRADE SECRET DATA BEGINS

Soot blowers are installed on the west face of level only. Sonic horns are installed on the north and south face of levels of each reactor. This platform is an integral part of platform system surrounding the SCR.

3.17.3.3 AIG platform

AIG platform is located to the east of SCR inlet duct. It provides the access to AIG piping and valves.

3.17.3.4 Sky bridges

sky bridges connecting the boiler building and SCR platforms are provided. The existing boiler building elevator could then be used to gain access to the SCR through the sky bridges.

3.17.3.5 SCR Stair Towers and Elevators

stair tower is located at the north of platform near the hoist zone. Another stair tower is located at the south of platform adjacent to the elevator. This south stair tower could also be used to gain access to the SDA penthouse and to the baghouse penthouse. Similarly, the elevator could have multiple stops to serve the SDA, baghouse as well as three levels of SCR platforms.

3.17.3.6 ID Fan and Motor Galleries

Galleries are typically provided around the ID fan and motor.

3.17.3.7 Other Miscellaneous Galleries

Miscellaneous galleries will be provided at the valve station, AIG, top of tanks, silos, and along the pipe rack.

The SCR platforms should be within in a weather enclosure. This includes roof panels above the top level, side panels on all sides of platforms, and checkered plates on grating on the level floor.

TRADE SECRET DATA ENDS]

3.18 ELECTRICAL

3.18.1 Description

The new AQCS equipment will require additional auxiliary power. As the mechanical systems are in the conceptual design phase, the proposed electrical power system design will reflect a conservative approach for providing power to the new system loads based on estimated loads as well as proven design concepts that have been successfully implemented on similar AQCS installations. In order to optimize system design, refinements and options will be explored during detailed design as specific vendor design data are developed.

3.18.2 New ID Fans [TRADE SECRET DATA BEGINS

In order to support the new AQCS systems, the four existing 4,000-hp ID fans will be replaced with new larger fans. The fan study (Appendix G, SL-010396) recommends a minimum of approximately for the motors of each new fan. However, experience has been that as detailed design progresses, this preliminary horsepower requirement typically increases. Additional design margins for future ductwork leakage and air heater pluggage can also contribute to this increase.

At this stage of conceptual design, in order to ensure that the electrical system can accommodate worst-case loading conditions, a conservative rating of for each fan will be assumed. The added margin does not change the approach to providing power to the AQCS equipment and fans but includes some margin in the size of the transformers. TRADE SECRET DATA ENDS]

3.18.3 Existing Plant Auxiliary Power System

If the new AQCS loads, including the new replacement ID fans, were added to the existing auxiliary power system, the net additional load would be approximately .

[TRADE SECRET DATA BEGINS

An examination of the capacity of the existing UAT (normal source) and the interchange transformer (startup and reserve source) was performed. The existing UAT top capacity rating is . Based on historical data and previous system study models, the current UAT maximum loading is . The remaining transformer capacity is . TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS

The existing interchange transformer tertiary winding capacity rating is . Based on historical data and previous system study models, the current transformer maximum loading is . The remaining transformer tertiary winding capacity is .

Compared with the estimated additional loading of , the remaining capacities of the transformers are not adequate to support the new loads. TRADE SECRET DATA ENDS]

3.18.4 AQCS Auxiliary Power System

As the existing power system is not adequate to provide power to all of the new loads, either replacement of the existing UAT and interchange transformers and their related power equipment or the addition of a new supplemental 13.8-kV system would be required.

Replacement of the existing main and startup/reserve systems would be extensive in that it would require replacement of upstream and downstream connections and equipment. The modifications would also have to be performed as part of an extended outage.

The installation of a separate AQCS system would be performed as a part of the pre-outage activities. The system would be installed, tested, and available for AQCS system pre-outage checkout and subsequent startup and commissioning. Based on the above, it is recommended that a separate new 13.8-kV system be used for this installation. Appendix J shows the new AQCS power system configuration.

The new system would include a new UAT connected to the existing isolated phase bus. A tap for this service near the existing UAT is already in place. For purposes of this conceptual design, a new startup/reserve source would be provided from a new 230-kV breaker in the switchyard connected to a new RAT located near the turbine building area via a 230-kV overhead line.

[TRADE SECRET DATA BEGINS

transformers would be connected to 13.8-kV switchgear main busses similar to the existing plant configuration. The transformers would be connected to the new switchgear via above grade cable bus. The 13.8-kV buses would provide power to double-ended 480-V substations, which would serve the loads for the SDA, SCR, lime preparation, and recycle systems. The new baghouse and associated fly ash loads would be fed from double-ended 480-V substations fed from the existing 13.8-kV baghouse feeds.

TRADE SECRET DATA ENDS]

The new ID fans would also be fed from the 13.8-kV buses. As described in the fan study, VFDs will be used for fan speed control. The drives have the added advantage of limiting motor starting current and short circuit contribution to the power system. The drives would be located in prefabricated buildings near the fans.

As confirmed with OTP, a new diesel generator will not be required.

3.18.5 Electrical Power Distribution [TRADE SECRET DATA BEGINS

The new electrical equipment would be housed in prefabricated electrical power distribution buildings strategically located near the new loads. They consist of a main electrical power distribution building, a lime preparation and recycle electrical building, and a baghouse electrical building. The locations are shown on the GA drawing in Appendix A. TRADE SECRET DATA ENDS]

The main AQCS electrical power distribution building would include a new 125-VDC control battery and uninterruptible power supply (UPS) and would house the new 13.8-kV switchgear lineups.

Cabling between the electrical buildings and the loads would be routed in above grade cable tray supported on new pipe racks or other structures as required. Once the cables were in the vicinity of buildings, the cables would enter the bottom of the building for ease of construction and maintenance.

3.19 CONTROLS

3.19.1 Description

The new AQCS systems will require additional controls for the new equipment and subsystems. The following describes the recommended conceptual design covering the control philosophy and strategy to incorporate the required controls.

3.19.2 DCS and Control Philosophy [TRADE SECRET DATA BEGINS

The new dry FGD, baghouse/SCR systems, and all BOP systems, including the electrical auxiliary power system, would be controlled and monitored in the DCS. The existing plant DCS would be extended with new controllers and inputs/outputs (I/O) to be provided for the dry FGD, baghouse, SCR, and other systems. They TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS

would be located remotely in the three new electrical equipment buildings. The exact number of new controllers will be determined after actual I/O count is finalized. The estimated I/O count for the project is approximately . It is recommended that a maximum of hardwired I/O be dedicated to each controller. The new DCS remote controllers and I/O would communicate with the plant main control room over redundant fiber optic data highways. TRADE SECRET DATA ENDS]

The new ID fans and associated equipment would be controlled from the existing unit furnace draft DCS controller with new remote I/O located near the fans in the baghouse area electrical building. The furnace draft controls logic will be upgraded to protect the gas path from implosion.

Human-machine interface (HMI) for the new dry FGD, baghouse, and all BOP systems would be from the existing operator consoles in the plant control room. New display/control screens and logic would be developed and installed in the DCS. New operator consoles would be added if needed dependent upon available space.

3.19.3 Instrumentation Philosophy

Wherever possible, transmitters would be used instead of switches. In general, transmitters would be the smart-type, two-wire design with National Electrical Manufacturers Association (NEMA) 4X enclosures.

Temperature instruments would be either thermocouples or resistance temperature detectors (RTDs) directly wired to the DCS without intermediate transducers. Thermocouples would be either Type E or Type K. RTDs would be 100 ohm.

Redundant instruments would be provided for critical services. As an example, triple-redundant transmitters for measuring ID fan outlet duct pressure for inlet vane control would be implemented.

[TRADE SECRET DATA BEGINS

Pneumatic modulating control valves would be provided with smart-type positioners, e.g., with outputs capable of directly communicating with the DCS. TRADE SECRET DATA ENDS]

3.20 DEMOLITION AND RELOCATION ACTIVITIES

The demolition and relocation activities anticipated to be performed throughout construction of the project are summarized below.

3.20.1 Demolition of Existing Baghouse and ID Fans [TRADE SECRET DATA BEGINS

The existing baghouse is required to remain active until the tie-in outage in . After the new baghouse is successfully brought in service, the existing baghouse and ID fans should be demolished as a post-outage activity to provide space for installing water treatment facilities. The demolition of the baghouse should include all inlet and outlet ductwork, walkways, galleries, and platforms supported off the baghouse structure.

TRADE SECRET DATA ENDS]

3.20.2 Demolition of Transformers East of Baghouse and Jamestown Boiler

The mentioned transformers and boiler should be removed if internal SCR support columns are to be installed.

3.20.3 Rerouting of Ash Pipe from Existing Baghouse to Ash Silo

The relocation of ash pipe onto the new pipe rack should be completed as an early activity to provide space for installing SDA foundations.

3.20.4 Modification and Extension of Existing Auxiliary Boiler Stack

The exhaust stack of existing auxiliary boiler will have to be kinked north to clear the SCR and extended above the top SCR platform level for safety reasons.

3.20.5 Demolition of Existing Breeching Ducts

Breeching openings of existing chimney will continue to be used for the new flue gas route. As a result, the existing breeching piece will have to be reconfigured as part of new ductwork.

3.20.6 Modification of Air Heater and Boiler Building Steel

As mentioned above in subsection 3.17.2, the existing structure would have to be modified for stability and for space clearance requirement.

3.21 CONSTRUCTIBILITY

3.21.1 Description

The constructibility review process should be continued through the detailed design process and through the bidding process to contract award. Any subsequent design changes should then be evaluated from a constructibility standpoint. Note that all directions noted below are grid (plant) directions.

Constructibility of a new SDA, SCR, and baghouse, along with demolition of the existing baghouse is enhanced by:

- Open areas where the new FGD, baghouse and support equipment are to be located.
- Open areas adjacent to each side of the boiler building to use as cranes operations and pick areas.

A challenging issue will be coordination of outage work in the area just north of boiler building column row K. A detailed plan will need to be developed for outage work, including equipment handling sequences for baghouse demolition, SCR ductwork connection, and boiler modifications. With boiler modification work and other outage work planned in parallel with SCR ductwork connection, it is advisable to establish a single point of contact as the person to ensure that as overhead loads are secured, others are notified that they can resume work. This will minimize the risk of outage delays due to inefficient communications.

3.21.2 Site Access

Due to the 48th Avenue railroad above the road, equipment delivery traffic will be from the east on 144th St. Route 109 bridge load capacity should be checked by the General Work Contractor when planning special permit heavy loads.

[TRADE SECRET DATA BEGINS

Rail access is also available with a separate "spur siding" that can be dedicated for staging new plant equipment prior to off-loading. The off-loading flexibility due to this isolated spur siding should be of value for the installation contractors. The condition of the spur siding should be determined and a cost estimate made for any refurbishment required. During the bidding process for the installation work, the bidders should indicate the value of the spur siding in order to provide cost savings input into the decision to refurbish the track. The capital cost estimate assumes that equipment and material will be delivered to the site via truck. There could be cost savings between deliveries via truck versus rail (   ); however, this can be reviewed further in detail engineering.

TRADE SECRET DATA ENDS]

Onsite roadways are in good condition. Grades and turning radii are suitable for heavy hauling and large-piece transport.

3.21.3 Construction Facilities [TRADE SECRET DATA BEGINS

Construction facilities, including laydown and staging areas, are depicted on the mark-up of the aerial photograph provided as Appendix O. The basic intent is to keep construction work force, estimated to peak at , on the south side of the plant, with the only exception being the demolition scrap material salvage area at the northeast corner of the site. TRADE SECRET DATA ENDS]

3.21.4 Crane Sizing and Selection

To increase efficiency and reduce cost, current AQCS demolition and installation trends involve the development of detailed, engineered lift plans for removal and installation of equipment and ductwork in large pieces. Each large piece lift would be approximately 15-20 tons at a boom radius in excess of 200 feet. The demolition and/or installation contactor will select its own equipment to perform the work and should be required by contract to identify and locate buried utilities and equipment to protect from crane ground bearing pressures. Appendix P shows crane operations and equipment staging areas from an equipment GA plan view.

3.21.4.1 West Side Crane [TRADE SECRET DATA BEGINS

The area due west of the boiler building is a key area for a crane operations and picking loads not only during the non-outage time period but also during the SDA and SCR tie-in outage. In support of large-piece non-outage and outage work plans, an 800-ton-class crane would be located in this area in order to build the SDA units and the SCR non-outage and would be critical for duct piece handling during the tie-in outage. A typical crane of this size used today is a with a counterweight attachment (illustrated in Figure 3-2). A crane operations area is depicted in the marked up GA drawing. TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS

Figure 3-2. with Counterweight Attachment

3.21.4.2 East Side Crane

The aisle way due east of the boiler building is an area that can be used for non-outage SCR installation on the east side and would be essential to support tie-in outage activities by easing the burden of the west side crane. A 250-ton-class crane, such as a , would be used. The crane operations area will be limited by the narrow aisle way created by the existing makeup water tank and the new stairway gallery for the new SCR. If the duct tie-in work is critical path for the outage (not the boiler modification work), a larger crane would be required (such as a) to handle large duct segments on the east side and to reduce outage time. The installation of the SCR stairway gallery can be postponed and the makeup water tank could be temporarily (or permanently) relocated in order to increase the width of the aisle way for crane operations. The crane will impede maintenance shop access and FD fan room access at times but those impediments can be scheduled.

TRADE SECRET DATA ENDS]

3.21.4.3 SDA and SCR Support Process Areas

Smaller-size lattice boom cranes or hydraulic truck cranes would be used to erect the various SDA and SCR support equipment.

3.21.5 Tie-In Outage

The final tie-in outage will involve four major activities:

- Existing baghouse ductwork, ID fan, and ID fan ductwork demolition and removal
- New SDA tie-in ductwork installation
- New SCR tie-in ductwork installation
- Boiler modifications

Cranes on each side of the boiler building would be shared for equipment handling for all of the outage activities. Openings in the boiler building north wall for SCR duct connections would be installed pre-outage. Any construction openings required in the north wall for boiler modification work would also be made pre-outage. The outage is discussed in more detail in Section 4 of this report.

Figure 3-3. Boiler Building Wall Openings

It is assumed at this time that the installing contractor would prefer north side boiler building access above the economizer discharge for movement and replacement of boiler modification equipment and components (boiler tubing panels). Due to the number and duration of outage activities required to install the SCR connecting ductwork in this area, consideration should be given to loading and removing boiler modification equipment and components into the east and west sides of the boiler building. Weld-out time to secure SCR duct connection pieces in order to release the crane may cause delays in moving boiler modification equipment and components.

Figure 3-4. Example of SCR Inlet Duct Installation During Plant Outage

Figure 3-5. Example of SCR Inlet Duct Lowering Into Position

If boiler modification work has to be performed from the north side in parallel with existing baghouse duct demolition and SCR ductwork connection during the outage, it would be advisable to establish a single point of contact as the person to ensure that as overhead loads are secured, others are notified that they can resume work. This will increase efficiency in work suspension required when overhead loads are suspended on a crane hook.

The tie-in outage sequence for the AQCS equipment is basically to:

- Remove the existing baghouse ductwork and ID fan outlet ducts.
- Install the new SDA and new ID fans tie-in ductwork.
- Install the new SCR discharge (lower) tie-in ductwork.
- Install the new SCR inlet (upper) tie-in ductwork.

Duct weld-out activities will be performed in parallel to the extent possible during periods when live loads are not suspended overhead.

With detailed advance planning, proper coordination of all outage activities in the congested area north of column row K, along with inclement winter weather protection, the outage work scope should be completed within the currently proposed schedule.

4. SCHEDULE

4.1 SCR AND FGD INSTALLED FOR SAME OUTAGE

The Level I implementation schedule shown in Appendix K is based on one major tie-in outage. This conceptual schedule was developed using the following input as a minimum: [TRADE SECRET DATA BEGINS

- Milestones provided by OTP during the June 8-9, 2010 kickoff meeting at the site.
- S&L in-house data and vendor input on current equipment procurement durations.
- The engineering study report provided in Appendix F.

The Level I implementation schedule (Appendix K) currently shows when engineering activities need to begin in order to support the award of the major equipment and installation procurements. These engineering activities will continue as necessary in order to complete the BOP engineering, procure remaining equipment, perform vendor drawing reviews, and support construction/startup and commissioning activities.

Only the major critical equipment and installation procurements were included in the schedule. For the AQCS project, a total of contracts will be developed. As shown in the Level I implementation schedule, procurement of the SCR catalyst and the dry FGD system, including baghouse equipment, need to start in . The SCR catalyst will be awarded with a limited notice to proceed to initiate the flow model scope of work and in order to hold all major expenditures of the project until after . Design input from these two contracts is required for the BOP engineering and to support the General Work Contract (GWC) specification bid issue in .

The schedule shows an award of one GWC Contract in early to allow the major underground and foundation work to be performed starting in through . The contracting strategy for the GWC Contract is currently planned to be a " ." Based on a review of the Level I implementation schedule, the civil and structural scope of work required for the project will be well-defined and site-specific. The mechanical and electrical scope of work will be based on the best available information and estimated material quantities. As the project progresses into the design and a more detailed level 3 schedule is developed, splitting the installation

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[TRADE SECRET DATA BEGINS

into GWC Contracts (e.g., underground and above ground) may be economically justified along with the contracting strategy. Issuing an above ground GWC specification for bids to months later than the underground GWC specification would allow the mechanical and electrical scope of work to be more complete and better defined.

The critical path for the outage construction is the boiler and air heater modifications, which are expected to take from the Contractor's access to the work. The schedule currently shows the maximum duration of weeks for this work (line item in the schedule). As a result, the finish date of the outage needs to move out into . The plant is loaded in and and the earliest the plant outage can start is in .

For startup and commissioning, approximately months is required after the unit goes back on line. Therefore, the earliest commercial operation date expected is in , which allows approximately months of float from the date mandated by law to have the AQCS in operation, . TRADE SECRET DATA ENDS]

4.2 FGD INSTALLATION FOLLOWED BY SCR INSTALLATION

[TRADE SECRET DATA BEGINS

During the screening study review, the feasibility of tie-in outages was discussed. Phasing the dry FGD system, including the baghouse system and ID fans with VFDs, into operation prior to the installation of the SCR system would be worth pursuing if capital costs could be reduced. At that time, the extent of the boiler modifications was unknown and more conceptual work needed to be performed. Based on further review of the Level I implementation schedule for one tie-in outage, a more detailed structural evaluation, and the length of the outage required for the boiler modifications, minimal capital cost savings, if any, are anticipated. Therefore, this option was not pursued further. TRADE SECRET DATA ENDS]

4.3 CASH FLOW

Appendix K to this report includes OTP's Level I implementation schedule for the project. The Big Stone Plant AQCS cash flow was developed based on the duration and sequence of the activities as dictated by the OTP schedule. In addition to the schedule, Appendix K also provides two plots that depict the cash flow and quarterly spending analyses. One scenario excludes allowance for funds used during construction (AFUDC) and the other excludes contingency, escalation, and AFUDC. The Direct and Construction Indirect Costs (Code of Account Line

[TRADE SECRET DATA BEGINS

Item in the Cost Estimates, Appendix H) were distributed based on a percent per month payment release typical to the contract type. A percentage was allocated for the award through the vendor drawing review and approval process, mobilization, pre-outage construction, and outage construction. Other project costs were distributed based on similar historical project cost distribution and customized for the project based on the OTP-provided dates for critical milestones: first major expenditure, outage durations, and seasonal weather conditions as they affect construction. TRADE SECRET DATA ENDS]

5. CAPITAL COST EVALUATION [TRADE SECRET DATA BEGINS

S&L estimated the capital cost for retrofitting dry FGD with new baghouse, dry FGD with reuse of the existing baghouse, wet FGD, and SCR. Estimated capital costs include the equipment, material, and labor based on . The underlying assumption is that the contracting arrangement for the project is on a multiple lump sum (not EPC) basis. The capital costs provided herein are based on burning 100% PRB coal and include the following:

- Equipment and material
- Installation labor
- Erection contractor profit
- General and administration
- Freight
- Sales tax
- Startup and commissioning
- Spare parts
- Indirect field costs and BOP engineering
- Contingency
- Owner's Engineer cost
- Escalation
- AFUDC

Costs for license fees and royalties are not included.

The installed capital costs are based on S&L in-house cost data from similar projects as well as vendor-supplied budgetary quotations. Based on the conceptual design that has been done, the costs have an accuracy of .

TRADE SECRET DATA ENDS]

Two estimates were prepared, one for the SCR and one for the dry FGD with baghouse. The costs are summarized in Table 5-1.

[TRADE SECRET DATA BEGINS

Table 5-1. Capital Cost Summary

Parameter	SCR	Dry FGD with New Baghouse
Direct and construction indirect cost,		
Indirect cost,		
Contingency @		
Escalation,		
Owner's cost,	Included in dry FGD	
Total project cost,		
Total AQCS Cost,		

TRADE SECRET DATA ENDS]

Detailed capital cost estimates for installing dry FGD and SCR at Big Stone, including major equipment, site modifications, and material items, are presented in Appendix H.

6. O&M COST EVALUATION

6.1 FIXED AND VARIABLE OPERATING COSTS [TRADE SECRET DATA BEGINS

The fixed O&M costs determined for this study consist of operating labor, maintenance labor, maintenance material, and administrative labor. The dry FGD will require an estimated additional full-time operators and maintenance personnel. Typical maintenance items for the dry FGD system would include the slakers, changing of atomizers, baghouse air compressors, booster fans, and recycle handling system. The SCR will require part-time operator to check the sonic horns, sootblowers, and ammonia system once per shift.

Annual maintenance material and labor costs shown herein are estimated based on technology operating experience in the U.S. The annual maintenance cost includes maintenance material for various subsystems and the labor required to perform the maintenance. The annual maintenance material and labor for the dry FGD technology is estimated to be of the direct and construction indirect cost. The annual maintenance material and labor for the SCR technology is estimated to be of the direct and construction indirect cost.

6.2 VARIABLE OPERATING COSTS

Variable O&M costs determined for each option include consumables, including reagent (lime and ammonia), byproduct management, bag replacement for the baghouse, catalyst, water, and power requirements. These costs were calculated at a unit capacity factor of . TRADE SECRET DATA ENDS]

Table 6-1 lists the major economic parameters that were used in the variable O&M costs as well as the economic evaluation. These values were developed both by OTP and S&L.

[TRADE SECRET DATA BEGINS

Table 6-1. Major Economic Parameters

Parameter	Value
Amortization life,	
Interest rate for discounting,	
Capital escalation rate,	
O&M escalation rate,	
Levelized fixed charge rate,	
Capacity factor,	
Auxiliary electric power energy charge,	
Ash disposal cost (placement only),	
Water,	
Lime (truck delivery),	
Activated carbon (truck delivery),	
Anhydrous ammonia (truck delivery),	

The variable cost for the dry FGD assumes that all generated fly ash solid waste will be land-filled and the current revenue stream for selling fly ash will be lost.

The variable O&M costs, such as reagent consumption, are associated with reducing the inlet sulfur to SO_2/MBtu and reducing the inlet NO_X to .

Auxiliary power costs developed reflect the increase in power requirements associated with the new ID fans as well as the estimated power consumption for the SCR, absorber, reagent preparation, and byproduct handling areas.

The fixed and variable O&M costs are summarized in Table 6-2.

Table 6-2. Fixed and Variable O&M Costs

Parameter	SCR	Dry FGD with New Baghouse
Fixed O&M,		
Variable O&M,		
Subtotal O&M,		
Total AQCS O&M,		

Detailed fixed and variable O&M costs for installing dry FGD and SCR at Big Stone are presented in Appendix I.

6.3 LEVELIZED COSTS [TRADE SECRET DATA BEGINS

Table 6-3 provides the annual, levelized cost for the dry FGD and SCR.

Table 6-3. Levelized Cost Summary

Parameter	SCR	Dry FGD with New Baghouse
Levelized investment,		
Levelized fixed O&M,		
Levelized variable O&M,		
Levelized subtotal cost,		
Levelized Total AQCS Cost,		

TRADE SECRET DATA ENDS]

7. PERMITTING CONSIDERATIONS

As described herein, OTP has initiated an AQCS retrofit program for Big Stone. The project includes the installation of advanced air pollution control systems, and is being initiated to ensure compliance with the anticipated South Dakota Regional Haze Rule. South Dakota published its Draft Regional Haze State Implementation Plan (SIP) in August 2010. The proposed regional haze regulations are included in the Administrative Rules of South Dakota (ARSD) Article 75:36. The proposed regulations require OTP to control NO_X, SO_2, and PM emissions from Big Stone using Best Available Retrofit Technology (BART).

Air pollution control systems proposed as part of the project include a selective catalytic reduction (SCR) system and separated overfire air (SOFA) for NO_X control, a dry flue gas desulfurization (FGD) system for SO_2 control, and a new fabric filter for PM control. While the existing fabric filter already meets the proposed BART requirements, replacing it as part of the overall AQCS project reduces the total project cost. The plans also incorporate activated carbon injection (ACI) for mercury control, although its installation is contingent upon EPA Maximum Available Control Technology (MACT) rulemaking.

Modifications to an existing stationary emissions source, including the installation of air pollution control systems, can trigger environmental permitting and approval requirements. Permitting requirements can include, but are not necessarily limited to, air, water, storm water, wastewater discharge, and solid waste handling and disposal permitting.

7.1 PERMITTING REQUIREMENTS

A report reviewing the environmental permits that may be required to implement the Big Stone AQCS project is provided in Appendix N to this report. Potential environmental permits include:

- South Dakota Air Construction Permit (ARSD Chapters 74:36:20 and 74:36:21)
- General Permit For Storm Water Discharges Associated With Construction Activities
- Revision to the facility's existing Solid Waste Permit

7.1.1 Air Permitting Summary

The South Dakota Regional Haze Program (ARSD Chapter 74:36:21) requires submittal of an application for an air permit to construct in accordance with ARSD Chapter 74:36:20. The air permit application will include information describing the air pollution control systems as well as information describing any new emission sources associated with the project (i.e., material handling sources). New emission point sources associated with the proposed material handling system include the:

- Lime storage silo
- Activated carbon storage silo
- FGD recycle solids storage silo
- FGD waste storage silo

Additionally, there will be new fugitive dust emissions associated with truck delivery of lime, anhydrous ammonia, and activated carbon to the plant; as well as truck delivery of FGD solids and fly ash from the storage silo to the landfill. Information describing the new emission points and fugitive dust sources must be included in the air permit application and is included in Appendix N to this report.

7.1.2 Wastewater and Storm Water Permitting Summary

South Dakota administers the National Pollutant Discharge Elimination System (NPDES) permitting requirements. Surface water discharge (SWD) permitting regulations are included in ARSD Chapter 74:52. In South Dakota, no person may directly discharge pollutants from any point source into surface waters of the state without a valid SWD permit (ARSD Chapter 74:52:01:04).

Big Stone is designed and operated as a zero process wastewater discharge facility; thus, an NPDES permit is not required for plant operation. OTP is proposing to install a spray dry absorber (SDA) FGD as part of the AQCS project. There are no liquid wastes generated from an SDA control system, as all water used in the control system is evaporated. Because the AQCS project retains the zero-liquid discharge design and operating criteria, the NPDES permitting requirements in ARSD Chapter 74:52 are not applicable to the project.

However, the NPDES Program also includes provisions for control of storm water discharges from industrial sources and storm water discharges associated with construction activities. In South Dakota, any construction activity disturbing one or more acres must have coverage under a storm water permit. On December 31, 2009, the South Dakota DENR reissued a General Permit for Storm Water Discharges Associated with Construction Activity. The storm water general permit includes runoff control requirements and work practices (e.g., grading and drainage requirements, silt fences, and retention ponds) designed to minimize impacts on surface waters associated with storm water runoff during construction activities. OTP will need to file a Notification of Construction Activity and develop a Storm Water Pollution Prevention Plan as required by the General Permit. The facility must complete and submit a Notice of Intent (NOI) prior to commencing construction activities.

All storm water discharges associated with industrial activities, including power generating facilities and chemical processing facilities, that discharge through municipal storm sewer systems or that discharge directly into the waters of the U.S. are required to obtain a NPDES storm water permit. The storm water control and discharge requirements will be included in the facility's NPDES discharge permit, and may require storm water retention, sampling, and analysis prior to discharge. In South Dakota, South Dakota DENR has a General Permit for Storm Water Discharges Associated with Industrial Activity. The permit covers any party meeting the conditions of the general permit. Upon completion of the AQCS project, the facility will be required to submit a Notice of Intent to apply for coverage under the General Permit for Storm Water Discharges Associated with Industrial Activity.

7.1.3 Solid Waste Permitting Summary

South Dakota Codified Law 34A-6 requires that for the purposes of proper, effective, and safe disposal of solid waste, any person intending to dispose of solid waste within South Dakota must comply with the provisions of state law. These provisions require a solid waste permit and establish requirements and procedures for obtaining the permit. The regulations developed to implement the solid waste statutes are found in ARSD Article 73:27. A permit from the South Dakota DENR Solid Waste Management Program is required prior to the construction of a solid waste disposal facility (ARSD Chapter 74:27:08:01). Permits are required before construction of the facility begins. Applications must address requirements listed in Chapter 74:27:09.

Based on information provided by OTP, the facility has an existing solid waste disposal facility permitted to accept coal combustion residues, including gypsum/sludge solids generated as part of the now canceled Big Stone I/Big Stone II common wet FGD system project. A Solid Waste Permit revision will likely be necessary to include reference to semi-dry FGD residue in the plant landfill and to remove references to the Big Stone I/Big Stone II common wet FGD system from the permit. It is anticipated that the permit revisions will be made during the scheduled permit renewal process.

7.2 PERMITTING EFFICIENCY AND TIMELINE

The overall goal of the environmental permitting program is to secure all of the permits and approvals needed to commence construction and operation of a proposed new source or modification to an existing source. From a regulatory standpoint, authorities use the permitting process to define legally binding requirements for individual sources to ensure compliance with the applicable environmental rules and regulations. The environmental permitting program should be implemented to support the overall project objectives and implementation schedule. To the extent possible, environmental permitting should not become the critical path or delay construction. Emission limits, discharge limits, environmental controls, and monitoring requirements in the final permit should, to the extent possible, be achievable and support the overall goals of the project. It is important that permit provisions align with technical capabilities of the environmental control systems being proposed (i.e., the technology must be capable of meeting the proposed permit limits). Failure to align permit provisions with control technology capabilities increases the risk of potential future compliance issues.

To minimize permitting risks and potential project delays it is important, as an initial step, to identify all of the environmental permits and approvals required to construct and operate the proposed facility or modification. This step requires the scope of the project to be fully defined and consideration of potential air, water, and solid waste implications of a proposed project. Failure to completely define the scope of the project, including potential impacts to all environmental media, increases the risk of missing a required permit and could lead to significant delays in the permitting process, legal challenges, and jeopardize start of construction and/or operation of the project.

Communication between the project proponent, third-party engineering and environmental consultants, and the permitting agency is also a necessary element of a successful permitting program. It is important to develop a clear division of responsibility and identify the parties responsible for developing the technical and environmental information needed to support the permit application. Environmental permitting regulations are designed to require a transparent review and decision making process, and typically include provisions for review and comment from interested parties. The permitting agency is required to develop a complete administrative record of the permitting process, and to make an informed decision based on the technical/environmental information in the record.

Therefore, it is important to establish clear lines of communications with the agency throughout the permitting process to ensure the agency receives the technical/environmental information needed to support its permit decisions.

Appendix N provides a report reviewing the environmental permits that may be required to implement the Big Stone AQCS retrofit project. Potential environmental permits include:

- South Dakota Air Construction Permit (ARSD Chapters 74:36:20 and 74:36:21)
- General Permit for Storm Water Discharges Associated with Construction Activities
- Revision to the facility's existing Solid Waste Permit

The most significant environmental permit needed for the proposed AQCS project is the Chapter 74:36:20 air construction permit for new sources or modifications; therefore, the remainder of this subsection focuses on preparation and submittal of the air construction permit application. The proposed South Dakota BART regulations require the Owner or operator of any BART-eligible source to submit an application to modify its operation in accordance with Chapter 74:36:20. OTP will be required to submit an application for a permit to construct that must describe the new air pollution control systems, emission limits, and monitoring requirements for Unit 1 and the new material handling emission sources. A construction permit may be issued by the South Dakota ENR only if it has been shown that the operation of the new source, or modification to an existing source, will not prevent or interfere with the attainment or maintenance of an applicable National Ambient Air Quality Standard (NAAQS), and that each new or modified source will comply with all applicable emission limits and other requirements. A simplified flow diagram showing the Chapter 74:36:20 permitting process is provided in Figure 7-1. Timeframes associated with the permit application review process are summarized in Table 7-1.

Figure 7-1. Chapter 74:36:20 Air Construction Permitting Process

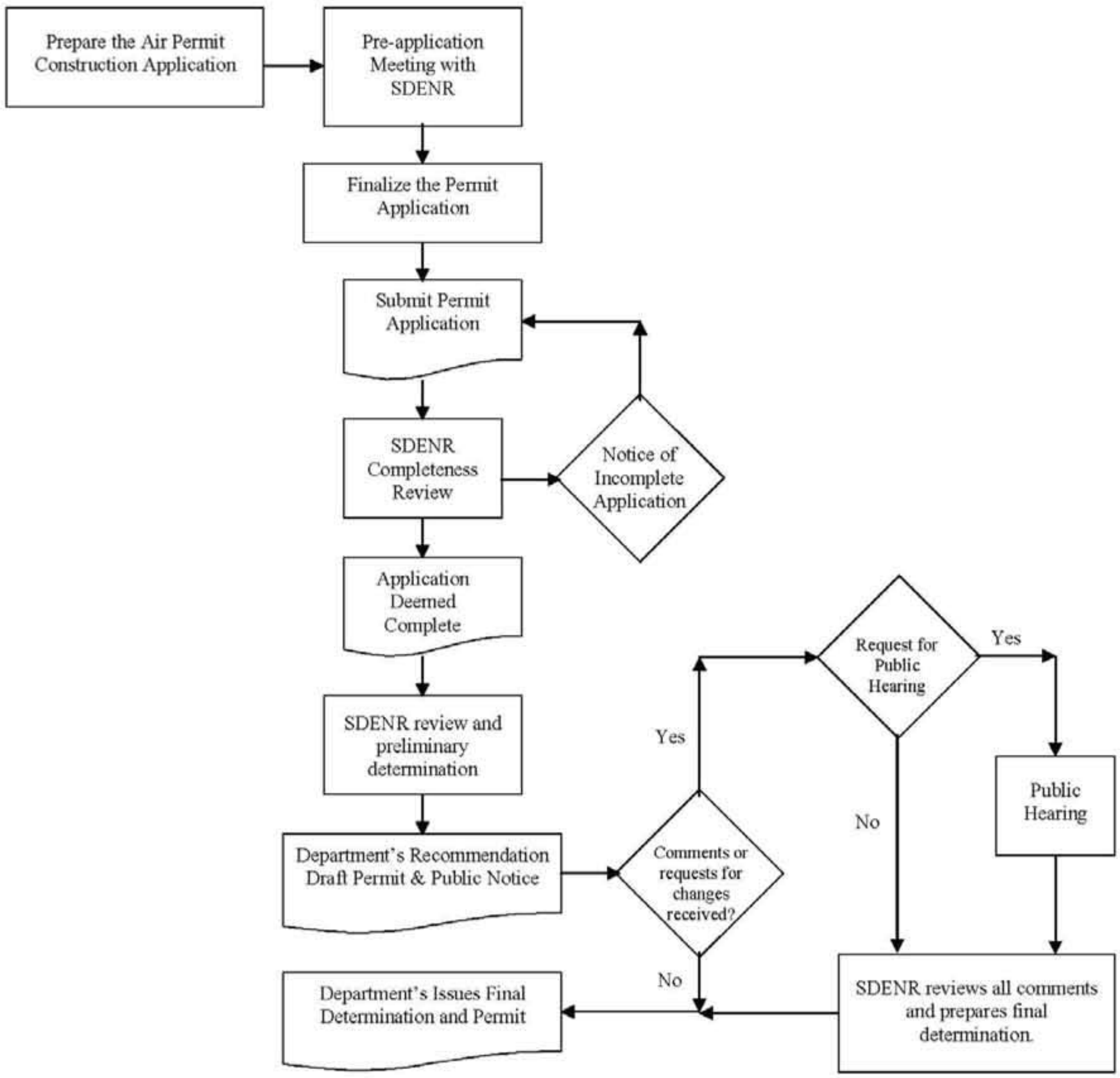


Table 7-1. Chapter 74:36:20 Air Construction Permitting Timeframes

Process/Chapter	Regulatory Requirement
Completeness Review 74:36:20:09	Within 30 days after submission of an application the department shall notify the applicant in writing whether or not the application is complete or incomplete. If the application is incomplete, the department shall identify the items required to complete the application. The applicant has 20 working days to submit the information, unless an extension beyond the 20 days is approved by the department. The department shall determine the adequacy of the applicant's response to each incomplete item within 15 days after receipt of the response and shall notify the applicant in writing if the application is or is not complete.
Department's Recommendation 74:36:20:10	The department shall recommend issuance or denial of a construction permit within 180 days after the submission of a complete application.
Public Participation 74:36:20:11 and 12	The department shall publish a public notice of the draft permit in a legal newspaper in the county where the source is located, including a statement that a person may submit comments or contest the draft permit within 30 days after the publication of the notice. During the public comment period, any interested person may submit written comments on the draft permit or request a contested hearing case.
Final Permit Decision 74:36:20:13	The department shall make its final permit decision within 30 days of the end of the public comment period on a draft permit. The department shall notify, in writing, the applicant and each person that submitted written comments. A final permit shall be issued within 30 days of the final decision, except under the following conditions: (1) A later effective date is specified in the final permit decision; (2) A contested case hearing is requested; or (3) No comments or request for changes in the draft permit were received during the public comment period on the draft permit. In this case, the draft permit automatically becomes the final permit decision and the final permit is issued at the end of the public comment period.
Right to Petition for Contested Case Hearing 74:36:20:14	The applicant or interested person may petition the board and obtain a contested case hearing to dispute the department's draft permit. Such petitions must comply with provisions of Chapter 74:09 and must be received by the department within 30-days after publication of the notice required by Chapter 74:36:20:11. An applicant or an interested person that comments on the draft permit may petition the board for and obtain a contested case hearing to dispute the department's final permit decision. Such petitions must comply with the provisions of Chapter 74:09 and must be received by the department within 30 days after receiving the department's final permit decision.

Chapter 74:36:20:06 requires any person who wishes to construct a new source or modify an existing source to submit a complete application to the South Dakota DENR at least 180 days before the estimated date of commencing construction of the new source or modification. Based on the review times summarized in Table 7-1, additional time should be added for the initial completeness review and the public participation process. A preliminary permitting timeline is summarized in Table 7-2.

Table 7-2. Preliminary Permitting Timeline

Activity	Days	Early Date	Late Date
Start Date	--	January 2011	January 2011
Prepare Permit Application	60 – 90		
Submit Permit Application	--	March 2011	April 2011
Initial Completeness Review	60 – 90		
Application Deemed Complete	--	May 2011	July 2011
Department Review	120 – 180		
Preliminary Determination/Draft Permit	--	September 2011	January 2012
Public Participation/Public Hearing	30 – 60		
End of Public Review Period	--	October 2011	March 2012
Department Review	30		
Final Determination	--	November 2011	April 2012

Because the department is under a regulatory mandate to issue its draft recommendation within 180 days of submission of a complete application, reaching "completeness" is critical to minimizing the overall permitting timeframe. Although the department is required to conduct its initial completeness review within 30 days of receiving an application, the department can return the application to the proponent during this period for additional details and information. Thus, to the extent possible, the applicant should endeavor to submit a thorough and complete application, including all of the technical/environmental information required by the department, to minimize the initial review period and start the 180-day countdown.

To be deemed complete, an air construction permit application submitted pursuant to Chapter 74:36:20 must include the following information:

- The following general company information:
  - The company name and address or the plant name and address if different from the company name.
  - The Owner's name and agent.
  - The plant site manager or contact.
- A description of the plant and its processes and products.
- The following information on emissions:
  - Identification and description of all emission units.
  - Fuels, fuel use, raw materials, and production rates.
  - Identification and description of air pollution control equipment.
  - Limitations on source operation affecting emissions or any work practice standards, if applicable, for all regulated air pollutants.
  - Other information required by any applicable requirements, including information related to stack height limits, such as the location of emission units, flow rates, building dimensions, and stack parameters, including height, diameter, and plume temperature for all pollutants regulated at the source.
- If available, a copy of any prepared plans and the specifications of any equipment or other facilities that may affect the source, including pollution control devices.
- A signed and notarized certification of applicant form.
- The results of any air dispersion modeling required by the department.
- The results of any stack performance testing required by the department.
- Any other information requested by the department that is relevant to determining compliance with the act or the Clean Air Act.

Finally, the potential for significant public interest in the permitting process must be taken into account when developing a permitting timeline. It is important to ensure that the department meets its public participation mandates, and to work with the department to address comments submitted during the public review process. Failure to assign an appropriate level of importance to public interest in a project can lead to permit application review delays, legal challenges, and jeopardize start of construction.

Chapter 74:36:20 provides two opportunities for interested parties to request a contested case hearing. First, the applicant or interested person may petition the Board of Minerals and Environment and obtain a contested case hearing to dispute the department's draft permit. Such petitions must be received by the department within 30 days after publication of the notice required by Chapter 74:36:20:11. Second, an applicant or interested person that comments on the draft permit may petition the Board and obtain a contested case hearing to dispute the department's final permit decision. Such petition must be received by the department within 30 days after receiving the department's final permit decision. Either petition must comply with the provisions of Chapter 74:09. Chapter 74:09 details the contested case hearing procedures, including timeframes for filing petitions, answers, pleading, motions, etc. Although the regulations provide specific timeframes, contested case hearings can add significantly to the overall permitting timeline, and should be considered a possibility in any permit application related to the construction or operation of a coal-fired electric generating unit (EGU).

7.3 FUTURE ENVIRONMENTAL REGULATIONS/LEGISLATION

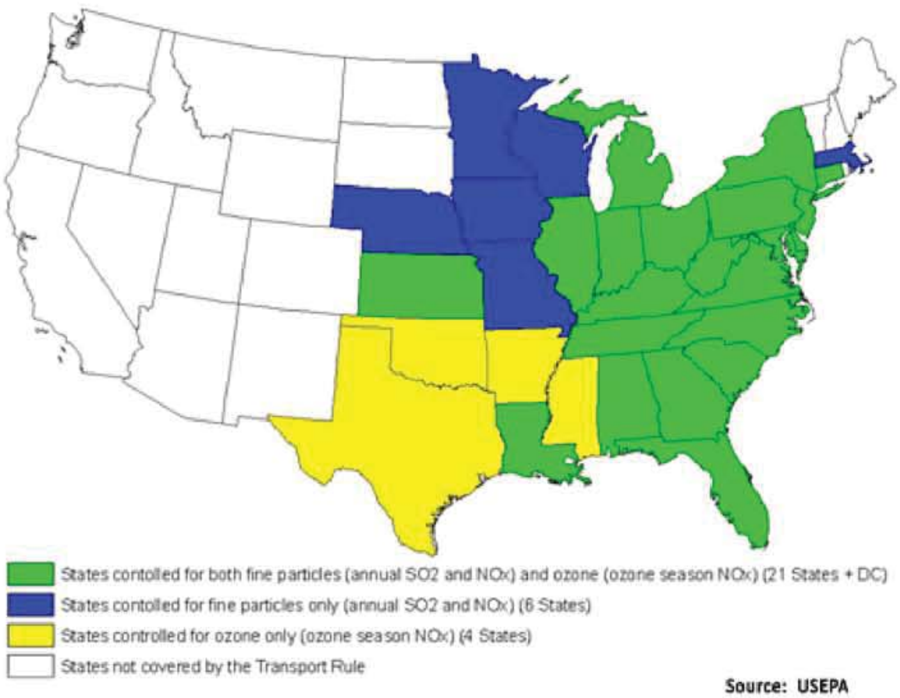
U.S.EPA is actively working on a number of environmental regulatory initiatives that may affect emissions from coal-fired electricity generating units such as Big Stone. This section of the report provides a summary of the future regulatory initiatives, and evaluates potential impacts to the AQCS project and operation of Big Stone.

7.3.1 Transport Rule

On July 6, 2010 EPA proposed the Transport Rule. The proposed rule would replace EPA's 2005 Clean Air Interstate Rule (CAIR). Both rules are intended to implement the Clean Air Act requirements concerning the transport of air pollutants across state boundaries, and assist downwind states to attain and maintain the NAAQS for ozone and fine particulate matter ($PM_{2.5}$). On July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated the 2005 CAIR in its entirety; however, after a rehearing of the case, the Court, on December 23, 2008, reinstated CAIR and directed the EPA to conduct further proceedings consistent with the Court's opinion in the case. As a result, CAIR went into effect in its entirety on January 1, 2009, and will remain in effect until the EPA re-writes the rule to address the flaws identified by the Court. The proposed Transport Rule responds to the court's concerns.

Specifically, the Transport Rule would require 31 states and the District of Columbia to reduce SO_2 and NO_X emissions from power plants that cross state lines and contribute to ozone and $PM_{2.5}$ NAAQS non-attainment in downwind states. Figure 7-2 shows the 31 states affected by the Transport Rule. Power plants located in South Dakota are not covered by the Transport Rule; therefore, the Transport Rule should have no impact on Big Stone operations.

Figure 7-2. States Affected by Transport Rule



7.3.2 Utility MACT

On December 14, 2000, EPA published a finding that the regulation of hazardous air pollutant (HAP) emissions from coal- and oil-fired utility steam electric generating units (EGUs) was appropriate and necessary, effectively adding coal- and oil-fired EGUs to the list of source categories under §112(c)(5) of the Clean Air Act.[1] On January 30, 2004 EPA published two alternative rules regulating mercury emissions from coal-fired EGUs.[2] The first proposal set mercury emission standards based on the maximum achieve control technology (MACT) developed pursuant to §112 of the Act (the "Proposed MACT Rule"). The alternative rule proposed revising EPA's December 20, 2000 regulatory finding, removing coal- and oil-fired EGUs from the list of source categories, and setting mercury emission standards for coal-fired EGUs pursuant to §111 of the Act. On March 29, 2005, EPA

[1] See, 65 FR 79825. Historically, electric utility steam generating units (EGUs) like Big Stone Unit have been excluded from the 40 CFR 63 Subpart B maximum achievable control technology (MACT) requirements. The regulations state that "[t]he requirements of [40 CFR Part 63 Subpart B] do not apply to electric utility steam generating units unless and until such time as these units are added to the source category list pursuant to section 112(c)(5) of the Act." (40 CFR 63.40(a)).. The December 2000 finding effectively added EGUs to the list of source categories.

published a final rule revising its December 2000 finding, concluding that is was neither appropriate nor necessary to regulate coal- and oil-fired EGUs pursuant to §112 (the "Revision Rule").[3] Based on this revised finding, EPA removed coal-fired utility units from the §112(c) list of source categories.

A final rule regulating mercury emissions from coal-fired EGUs was published on May 18, 2005.4 The Clean Air Mercury Rule (CAMR) established standards of performance for mercury emissions from both new and existing coal-fired utility units. Rather then regulating mercury pursuant to §112, CAMR was based on §111 of the Act. CAMR included a New Source Performance Standard (NSPS) for mercury emissions from new coal-fired units, and established a nationwide mercury cap-and-trade program applicable to both new and existing coal-fire units.

However, on February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating CAMR as well as EPA's Revision Rule.[5] The Court's ruling effectively vacated the CAMR regulations for both new and existing EGUs, and restored EPA's previous finding, published December 20, 2000, that the regulation of HAP emissions from coal- and oil-fired EGUs was appropriate and necessary. The Court's vacatur effectively reestablished coal- and oil-fired EGUs as a §112(c) source category of HAP emissions.

EPA is currently working on rewriting the Utility MACT Rule to address the Court's ruling. As part of this effort, EPA initiated an Information Collection Request (ICR), including a request that several existing coal fired EGUs conduct stack testing for a variety of HAP compounds. The ICR effort will provide EPA with the emissions data needed to establish the MACT emission limits, and will help EPA identify the MACT control technology requirements for new and existing coal-fired sources.[6] A proposed Utility MACT Rule is expected to be published by March 16, 2011, and a final Utility MACT rule is expected by November 16, 2011. The rule will include HAP emission standards for new and existing coal-fired EGUs, such as Big Stone.

It is not known how EPA will propose to regulate HAP emissions from coal-fired EGUs. However, based a review of the February 2008 Court of Appeals decision, it appears unlikely that the new rule would include an emissions trading program. Based on a review of the 2004 proposed Utility MACT Rule (69 FR 4652, January 2004), judicial

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2 60 FR 4652 (January 30, 2004)
3 70 FR 15994, March 29, 2005),
4 70 FR 28606 (May 18, 2005)
5 See, State of New Jersey v. Environmental Protection Agency, 517 F.3d 574 (D.C. Cir. 2008).
6 More information on the Utility MACT ICR can be found at: http://utilitymacticr.rti.org/

[TRADE SECRET DATA BEGINS

decisions addressing MACT rules,[7] and the recently published proposed Industrial Boiler MACT rule (57 FR 32006, June 2010), it is likely that the new Utility MACT rule would include the following provisions:

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Although it is anticipated that that the Utility MACT rule will regulate a number of HAPs and HAP categories, and that the rule will likely include stringent MACT emission limits, it does not appear that the rule will trigger additional air pollution controls for Big Stone (beyond those proposed for the AQCS project). are captured in air pollution control systems designed to control SO_2 emissions. The proposed SDA with baghouse should provide the most effective , and should represent MACT for existing sources firing sub-bituminous coal. are effectively captured in particulate control systems, and the

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proposed fabric filter baghouse should represent MACT for . The SDA with baghouse coupled with the proposed ACI control system should represent MACT for mercury control. Finally, combustion controls should represent MACT for the . There is some concern that combustion systems designed for low-NO_X operation may not be able to simultaneously achieve . OTP should closely follow the Utility MACT rulemaking process to ascertain whether EPA will propose to limit emissions as a surrogate for , and determine whether any proposed limit is achievable with low-NO_X combustion.

TRADE SECRET DATA ENDS]

7.3.3 National Ambient Air Quality Standards

EPA has recently proposed and finalized several NAAQS revisions. The NAAQS revisions will likely increase the number of non-attainment areas in the U.S. The following subsections highlight NAAQS revisions that could impact OTP's pollution control strategy.

7.3.3.1 PM2.5 NAAQS

In 1997, EPA revised the NAAQS for PM to add new standards for fine particles, using $PM_{2.5}$ as the indicator. EPA established primary annual and 24-hour standards for $PM_{2.5}$ of 15 $\mu g/m^3$ and 65 $\mu g/m^3$, respectively. On October 17, 2006, EPA revised the primary and secondary NAAQS for $PM_{2.5}$. In that rulemaking, EPA reduced the 24-hour NAAQS for $PM_{2.5}$ to 35 $\mu g/m^3$, and retained the existing annual $PM_{2.5}$ NAAQS of 15 $\mu g/m^3$. On February 24, 2009, the U.S. Court of Appeals for the District of Columbia issued rulings on litigation involving the 2007 $PM_{2.5}$ NAAQS.[8] Among other things, the Court remanded the annual primary $PM_{2.5}$ standard of 15 $\mu g/m^3$ to EPA because the agency failed to explain adequately why this level is "requisite to protect the public health." In response to the Court's decision, EPA is considering lowering the annual $PM_{2.5}$ NAAQS to 12 - 14 $\mu g/m^3$. EPA is expected to issue a Notice of Proposed Rulemaking (NPRM) by the end of 2010.

Currently, all areas of South Dakota are in attainment with the 1997 and 2006 $PM_{2.5}$ NAAQS. If EPA proposes an annual standard that changes the status of areas in South Dakota to non-attainment, the state of South Dakota would be required to modify its State Implementation Plan (SIP) and could require OTP to install control equipment to

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reduce emissions of primary and secondary $PM_{2.5}$ (e.g., SO_2 and NO_X). However, even if EPA lowers the $PM_{2.5}$ NAAQS, it appears unlikely that any counties in South Dakota would be designated non-attainment, or that compliance with the more stringent NAAQS would require emission reductions from Big Stone beyond those required by BART. Assuming EPA revises the $PM_{2.5}$ NAAQS, a potential timeline could be as follows: (1) EPA issues the NPRM by the end of 2010; (2) EPA publishes a final rule by the end of 2011; (3) EPA issues final area designations by 2013; (4) EPA approves South Dakota's final SIP in 2016 (if any areas in South Dakota were designated non-attainment); and (5) emission controls on affected units would have to be installed in the 2019 timeframe.

7.3.3.2 Ozone NAAQS

In 2008, EPA reduced the 8-hour ozone NAAQS from 80-75 ppb. Final area designations are expected by March 2011. In a letter dated March 6, 2009, South Dakota's Secretary of DENR sent a letter to U.S. EPA with recommendations for designation of areas of the state for the 2008 revised 8-hour ozone NAAQS. In that letter, the Secretary proposed that all counties in South Dakota be designated in attainment with the 2008 8-hour ozone NAAQS.

On January 19, 2010, EPA proposed lowering the 8-hour ozone standard even further to 60-70 ppb. A lower 8-hour ozone standard would be expected to result in more non-attainment areas. A more stringent NAAQS would require the South Dakota to re-elevate the attainment status of areas within the state. However, based on the ambient ozone data included in South Dakota's March 6, 2009 letter to EPA, it appears that most of the state would be in attainment with the more stringent NAAQS. EPA intends to complete reconsideration of the 8-hour ozone NAAQS before the end of 2010. Even if EPA lowers the 8-hour ozone NAAQS, it appears unlikely that compliance with the more stringent NAAQS would require emission reductions from Big Stone beyond those required by BART.

7.3.3.3 Nitrogen Dioxide NAAQS

On February 9, 2010, EPA published its final nitrogen dioxide (NO_2) NAAQS rule, setting a new 1-hour NO_2 standard of 100 ppb, and retaining the current annual NO_2 standard of 53 ppb. The effective date of the new standard was April 12, 2010. All areas of South Dakota are currently in attainment with the annual NO_2 NAAQS; however, the State will be required to designate areas as attainment/non-attainment with the new 1-hour standard.

EPA expects to designate areas as attainment or non-attainment by January 2012 based on the existing community-wide ambient air quality monitoring network. In the event areas within South Dakota are designated non-attainment, the State would be required to modify its SIP and could require OTP to install control equipment to reduce emissions of NO_X. However, it appears unlikely that compliance with the more stringent NAAQS would require emission reductions from Big Stone beyond those required by BART. If EPA designates areas of South Dakota as non-attainment, EPA would be expected to approve the final South Dakota SIP by 2015 to 2016, and could require control technologies to be installed in the 2018 timeframe.

7.3.3.4 SO_2 NAAQS

On June 2, 2010 EPA published a final revision to the NAAQS for SO_2. In the final rule EPA revised the primary SO_2 standard by establishing a new 1-hour standard at a level of 75 ppb. EPA also revoked the two existing primary standards of 140 ppb (24 hours) and 30 ppb (annual) because it was determined that they would not add additional public health protection beyond that provided by the new 1-hour standard.

All areas of South Dakota were in attainment with the 24-hour and annual SO_2 NAAQS. South Dakota will be required to re-visit its designations for compliance with the new 1-hour standard. Unlike other NAAQS implementation rules, EPA plans to use refined dispersion modeling to determine if areas with sources that have the potential to cause or contribute to a violation of the new standard can comply with the standard. EPA intends to complete designations by June 2012, and anticipates designating areas based on 2008-2010 ambient air quality monitoring data and/or refined dispersion modeling results.

In the event areas of South Dakota are designated as non-attainment, the state would need to submit its revised SIP in 2014. SIP revisions would describe the actions that South Dakota would take to come into compliance with the new standard, and could require OTP to install control equipment to reduce emissions of SO_2. However, it appears unlikely that compliance with the more stringent NAAQS would require emission reductions from Big Stone beyond those required by BART. EPA would be expected to approve the final South Dakota SIP by 2015 to 2017, and could require control technologies to be installed in the 2018–2019 timeframe.

7.3.4 Status of Potential Future Greenhouse Gas Regulations

7.3.4.1 Greenhouse Gas Legislation

Over the past couple of years, several legislative initiatives have been introduced in Congress addressing greenhouse gas (GHG) emissions, clean energy technologies, climate change, and energy efficiency. To become law, any GHG legislation must be approved independently by both the House of Representatives and the Senate, coming together in conference committee to reconcile any differences. This process must be completed during the same two-year congressional session. The current congressional session ends December 2010.

In June 2009, the House of Representatives passed the American Clean Energy and Security Act of 2009 (H.R. 2454). The bill included a GHG cap-and-trade program that encompassed most large industrial sectors (including power plants), and included emission caps that would reduce aggregate GHG emissions to 3% below their 2005 levels in 2012; 17% below 2005 levels by 2020; 42% below 2005 levels by 2030, and 83% below 2005 levels by 2050. The bill also included provisions related to a federal renewable electricity and efficiency standard, carbon capture and storage technology development, performance standards for new coal-fired power plants, R&D support for electric vehicles, and support for deployment of smart grid advancement. The Senate has not, however, produced a companion bill. Several senate bills were considered in 2010, including the American Clean Energy Leadership Act (S.1462) and the American Power Act (S.1733). The American Clean Energy Leadership Act (sponsored by Senator Bingaman) sought to accelerate the introduction of new clean energy technologies and increase energy efficiency, but did not set a price on carbon and did not have quantifiable reductions in GHG emissions. The American Power Act (sponsored by Senators Kerry and Lieberman) sought to achieve aggregate GHG emission reductions of 20% below 2005 levels by 2020 and by 83% by 2050 through a nationwide cap-and-trade program. The bill also included provisions encouraging investments in clean energy technology and the creation of green jobs.

At present, it appears unlikely that Congress will pass GHG legislation during this congressional session. If the Senate does not act in the remaining months of 2010, both chambers must start the process from the beginning to pass new bills during the next session that begins January 2011.

7.3.4.2 Greenhouse Gas Regulations

Unless legal challenges or opposition in Congress succeed in stripping EPA of its authority to regulate GHG emissions under the Clean Air Act, EPA is expected to require major stationary sources to account for GHG emissions by early 2011. On May 13, 2010, U.S.EPA released a final rule intended to clarify how CAA permitting requirements, including the PSD program, will be applied to GHG emissions from power plants and other stationary facilities. The rule is commonly known as the "Tailoring Rule" because it adjusts the PSD threshold requirements applicable to other NSR-regulated pollutants to make them appropriate for GHG emissions.

The Tailoring Rule applies to six GHGs: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Because some GHGs have greater potential to effect global warming than others, the rule expresses GHG emission thresholds in "carbon dioxide equivalents" or "CO2e." The CO2e metric translates emissions of gases other than CO_2 into the CO_2 equivalent based on the climate change potential of each gas. Total GHG emissions are calculated by summing the CO2e emissions of all six regulated GHGs.

The Tailoring Rule establishes two initial steps for phasing in regulation of GHGs:

- Step 1 (January 2, 2011, through June 30, 2011):
  - — GHGs must be addressed in PSD preconstruction permits for new or modified facilities that require a PSD permit based on their emissions of other regulated pollutants (SO_2, PM, etc.) and that increase net GHG emissions by at least 75,000 tons per year CO2e.
  - — GHGs must be addressed in Title V operating permits for all facilities that require a Title V permit based on their emissions of other regulated pollutants.
- Step 2 (July 1, 2011, through June 30, 2013):
  - — GHGs must be addressed in PSD preconstruction permits for new facilities that have the potential to emit at least 100,000 tons per year CO2e, even if they would not require a PSD permit based on their emissions of other regulated pollutants.
  - — GHGs must be addressed in PSD preconstruction permits for modifications of existing facilities that increase net GHG emissions by at least 75,000 tons per year CO2e, even if they would not require a PSD permit based on their emissions of other regulated pollutants.
  - — GHGs must be addressed in Title V operating permits for all facilities that have the potential to emit at least 100,000 tons per year CO2e, even if they would not require a Title V permit based on their emissions of other regulated pollutants.

Most power plants are already required to have a Title V Operating Permit based on emissions of other regulated pollutants, and have the potential to emit considerably more than 100,000 tons per year CO2e. Therefore, the facility will need to modify its existing Title V Operating Permit to address GHG emissions; however, this regulatory requirement is not part of the AQCS project.

7.3.5 Coal Combustion Residue Regulations

On May 4, 2010, the U.S. EPA proposed alternative approaches to regulate the disposal of coal combustion residuals (CCRs), including both ash and flue gas desulfurization wastes, generated by electric utilities and independent power producers. Beneficial use of CCRs in products such as concrete or wallboard would be not regulated under the proposal. Placement of CCRs as fill in quarries or gravel pits would be considered disposal and would be regulated, but placement in coal mine voids would not.

The proposal requests comments on two primary alternatives: one would regulate CCRs as "special wastes" under the hazardous waste provisions of Subtitle C of the Resource Conservation and Recovery Act (RCRA); the other would regulate CCRs under the non-hazardous waste provisions of RCRA Subtitle D. An important difference between the two is that the Subtitle C approach would regulate CCRs from the point of generation through the point of final disposal. This would include stringent requirements for facilities that generate, transport, store, treat, and dispose of CCRs. The Subtitle D approach, in contrast, would regulate only the disposal of CCRs. However, the disposal requirements of the two approaches have many similarities, including standards for siting, liners, groundwater monitoring, corrective action for releases, closure of disposal units, and post-closure care.

Other significant differences and similarities are summarized below:

- Effective Dates: Under Subtitle C, the effective date of the requirements would be variable, because each state would have to develop and promulgate its own implementing regulations. According to EPA, this process could take two years or more. Under Subtitle D, the proposed federal standards would take effect within 180 days after promulgation of the final rule.
- Enforcement: Subtitle C would allow for enforcement by EPA and state agencies, while Subtitle D would not be enforced by EPA. States could enforce their Subtitle D regulations, and citizens could file lawsuits against offending facilities.
- Permitting: Under Subtitle C, regulated facilities would be required to obtain permits for the units in which CCRs are disposed, treated, and stored. Under Subtitle D, there would be no federal permitting requirements, but states would be free to require permits under their own regulations.

- Existing Surface Impoundments: Under Subtitle C, surface impoundments constructed before the rule is finalized must either remove solids and retrofit the impoundment with a composite liner within five years of the effective date, or stop receiving CCRs within five years and then close the unit within two years thereafter. Under Subtitle D, existing surface impoundments must remove solids and retrofit with a composite liner, or stop receiving CCRs and close the unit within five years of the effective date.
- Existing Landfills: Under either Subtitle C or Subtitle D, landfills built before the rule is finalized are not required to retrofit with a new liner or leachate collection system. However, under either approach, an existing landfill must comply with groundwater monitoring requirements.
- New Surface Impoundments: Under either Subtitle C or Subtitle D, surface impoundments constructed after the rule is finalized are required to meet a new set of technological requirements specific to CCRs. These requirements include a composite liner and a leachate collection and removal system. Additionally, under Subtitle C, CCRs are subject to treatment requirements that EPA has stated are intended to phase out the use of new surface impoundments.
- New Landfills: Under either Subtitle C or Subtitle D, new landfills and lateral expansions of existing landfills must meet technological requirements that include composite liners, leachate collection and removal systems, and groundwater monitoring.

As stated above, the proposal does not intend to regulate the beneficial use of CCRs. However, industry representatives have raised concerns that the Subtitle C approach could have a detrimental effect on beneficial use, because of the permitting and technical requirements that might apply to the storage and transportation of CCRs before they are used. Additionally, the proposal requests comments on possible changes to the definition of beneficial use, intended to clarify when the use of CCRs constitutes an exempt beneficial use. Specifically, EPA has proposed to consider the following factors in deciding whether a use is beneficial: 1) the CCR used must provide a functional benefit; 2) the CCR used must substitute for the use of a natural material, thereby conserving a natural resource; and 3) CCRs would be expected to meet any applicable product specifications, regulatory standards, or relevant agricultural standards. EPA has not published an expected date for finalizing the rule after comments are considered.

As discussed above, the facility has an existing solid waste disposal system permitted to accept CCRs. Based on a review of the proposed CCR regulations, it does not appear that the proposed regulations would have a significant impact on the design or operation of the existing solid waste disposal facility if EPA chooses to regulate CCRs under the non-hazardous waste provisions of RCRA Subtitle D. However, regulating CCR as “special wastes” under the hazardous waste provisions of Subtitle C of RCRA could have a significant impact on the design and operation of the facility. OTP should continue to monitor the EPA’s CCR rulemaking efforts.

8. NEXT STEPS

Items recommended as the next steps prior to detailed design are summarized below.

Development of a detailed procurement plan is an important next step. This plan will identify the contracting approach, number of contracts, long lead time equipment, and the division of responsibility for each contract. Additionally, the schedule can be developed in more detail and the cash flow formalized.

Conceptual engineering on the AQCS retrofit project should be initiated to refine items from the study and reduce risk on the cost estimate. This conceptual engineering should be initiated in 2010 and 2011 and should include:

- Evaluate a more typical heat input for equipment sizing.
- Evaluate cost-adder to operate the SCR up to 830°F versus boiler retrofits. [TRADE SECRET DATA BEGINS
- Revisit SCR reagent study based on SCR inlet NO_X.TRADE SECRET DATA ENDS]
- Federal, state, and local permit evaluations.
- Construction tie-in plans with diagrams, crane positions, and detailed outage schedules.
- Conceptual engineering of the auxiliary power supply system, including refinement of the single line, detailed evaluation of the auxiliary power supply system, and others.
- Investigations of the underground utilities and subsurface investigation.
- Flow model using mathematical model for the air preheater outlet duct and other areas.
- Layout and utility relocations.
- Piping and instrumentation diagrams to be prepared to define interconnections with existing plant systems.

PUBLIC DOCUMENT - TRADE SECRET - PRIVATE DATA HAS BEEN EXCISED

ATTACHMENT 5

BIG STONE PLANT AQCS PROJECT COST ESTIMATE

Optimizations and Basis

Big Stone Plant AQCS Project
Summary of Cost Optimizations

[TRADE SECRET DATA BEGINS

Item	Description	Dry FGD	SCR
1	ACI costs to be deferred and separated out from the dry FGD estimate. Separate ACI estimate prepared.	X	
2	Water treating costs to be deferred and separated out from the dry FGD estimate. Separate water treating estimate prepared.	X	
3	Scraper building size reduced by	X	
4	new scrapers deleted from dry FGD estimate	X	
5	New baghouse compressors deleted from dry FGD estimate. Plan to re-use existing compressors.	X	
6	Scale back SCR enclosure to only enclose soot blower level.		X
7	Scale back boiler modifications to only replace the smaller primary bank and not the larger primary bank.		X
8	Reduced boiler steel modifications for the SCR from tons to tons.		X
9	Reduced installation manhours required for duct and SCR from manhours/ton to manhours/ton.	X	X
10	Optimized overtime and per diem from hr days to hr days due to high unemployment rate.	X	X
11	Scaled back freight costs on equipment especially in regards to subcontract for boiler modifications.		X
12	Scaled back scaffolding costs from % to % (i.e. to).	X	X
13	Optimized crane rental operator manhours due to reduction in overtime.	X	X
14	Scaled back % excise tax on equipment, structural steel, and ductwork.	X	X

TRADE SECRET DATA ENDS]

Sargent & Lundy LLC

Otter Tail 09/24/10
Big Stone Station Unit 1
SO2, NOx and Mercury Reduction Strategies

BASIS OF COST ESTIMATE

Project No.: 12715-001
Estimate & Rev. No.: 30859A (DFGD) and 30866A (SCR)
Preparer: RCK / MNO

[TRADE SECRET DATA BEGINS

General Information

Type of estimate – Conceptual with +/- % cost estimate accuracy.
Project location – Milbank, South Dakota
MW rating of Unit 1: 495 MW Gross
Unit of measurement in cost estimate –
Currency – .
Unique site issues – None.
Contracting strategy –

TRADE SECRET DATA ENDS]

Scope: These cost estimates are for the installation of one new Dry Flue Gas Desulphurization (DFGD) System with Fabric Filter (Baghouse) and Activated Carbon Injection System (Estimate 30859A) and a Selective Catalytic Reduction (SCR) System (Estimate 30866A).

[TRADE SECRET DATA BEGINS

The DFGD System consists of spray dryer absorber towers. The existing baghouse structure will be abandoned/removed with new % Baghouses constructed with ductwork modifications as required. The existing ID Fans will be removed and replaced with new centrifugal ID fans and variable frequency drives. A Reagent Preparation System, a Recycle System, and a Solid Waste Handling System will be installed. An Activated Carbon Injection System (ACI) will be installed for mercury reduction. Other auxiliary systems include service water system and piping, auxiliary power and power distribution for the equipment and civil improvements and other improvements as required.

An SCR system will be installed with new reactors. SCR installation will require extensive boiler work including reheater, primary superheater, economizer modifications, a new Separated Overfire Air System and sootblower additions. An Anhydrous Ammonia System will be added along with other necessary equipment to support system operation. TRADE SECRET DATA ENDS]

Construction [TRADE SECRET DATA BEGINS

Labor profile - .

Labor wage rate selected for the estimate - rates for Sioux Falls, South Dakota. Base craft rates are as published in RS Means Labor Rates for the Construction Industry, Edition. The craft rates are then incorporated into work crews appropriate for the activities by adding allowances for small tools, construction equipment, insurance, and site overheads to arrive at crew rates detailed in the cost estimate. A regional labor productivity multiplier is included based on the Compass International Global Construction Yearbook.

Labor Work Schedule and Incentives - Assumed work week. Allowances have been made for the pre-outage and outage related work, which may require work week ( ). It is assumed that % of total labor hours shown in the cost estimate will be expended during the pre-outage work and the remaining % during the outage. All labor hours are subject to $ /hr per diem subsistence as labor incentives to attract skilled labor to job site.

Procurements – Cost Basis

Budgetary vendor pricing was obtained for the DFGD system, the Solid Waste Handling System, Water Treatment System and the Anhydrous Ammonia System. Steel silo pricing, pumps, power transformers and other small equipment pricing are recent for similar size equipment (within last months).

S&L database pricing was used for all commodity based materials, such as piping, concrete, instrumentation and wiring.

No actual procurement at this phase of the project.

Project Indirect Costs

Heavy Construction Equipment: will be shown as a cost with separate freight, assembly and teardown costs and full time crane operator and oiler for the duration of crane usage.

Mobilization / Demobilization: included in labor wage rates unless multiple mobilization / demobilization is needed.

Scaffolding: % of total material and labor costs

Consumables: % of total material and labor cost

Allowance for Overtime: Included at times the base rate + taxes + insurance for pre-outage and outage work.

TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS

Freight: % of total equipment and material cost.
Sales Tax: % sales tax has been applied on equipment, material and labor, plus % excise tax on contractor's gross receipts. It is assumed that excise tax is not applicable to Engineering, Construction Management, Start-up & Commissioning and Owner's Costs. Therefore, only % sales tax has been applied to these items.
Contractor's G&A and Profit: G&A at % and Profit at % of total material and labor costs
Engineering: % of total direct cost
Construction Management: % of total direct cost
Start-up & Commissioning: % of total direct cost
Start-up Spare Parts: Included at % of equipment cost for the SCR and at % of equipment cost for the DFGD.
Owner's Cost: cost is provided by OTP and included in the DFGD estimate for both the DFGD and the SCR Projects.
Excess Liability Insurance: At % of total direct cost.
Interest During Construction (Allowed for Funds During Construction): By OTP.

Escalation

Included at %/yr of equipment, material, labor and indirect costs starting from until .

Contingency

We recommend that % be used as the project contingency value at this time. The basis for that is as follows:

- Less than % of the engineering required to design this facility has been completed to date.
- Vendor quotes were received for less than of the equipment and material costs.
- We had an independent estimate performed by for the construction costs and their results did not match our estimate but were close enough to confirm that the estimate (before contingency) is reasonable.
- The project itself is fairly similar to our completed projects other than the support of the SCR and the demolition of the existing baghouses.
- The costs of SCR's are very sensitive to the physical aspects of each project and can be difficult to predict until more of the detailed design is completed. Our data indicates that a contingency of % will cover those variations.

TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS

- The market is currently stable but has been very sensitive to governmental influences in the recent past. If pending regulatory decisions are made in a way that will cause a large number of utilities to begin projects similar to this in the same timeframe, % contingency may not be enough. Sudden changes such as those are best dealt with once the impact of regulatory changes can be quantified and should be outside of our recommended value.

TRADE SECRET DATA ENDS]

Scope Excluded or By Others

In order to establish the overall project costs, the following items must also be accounted for by OTP:

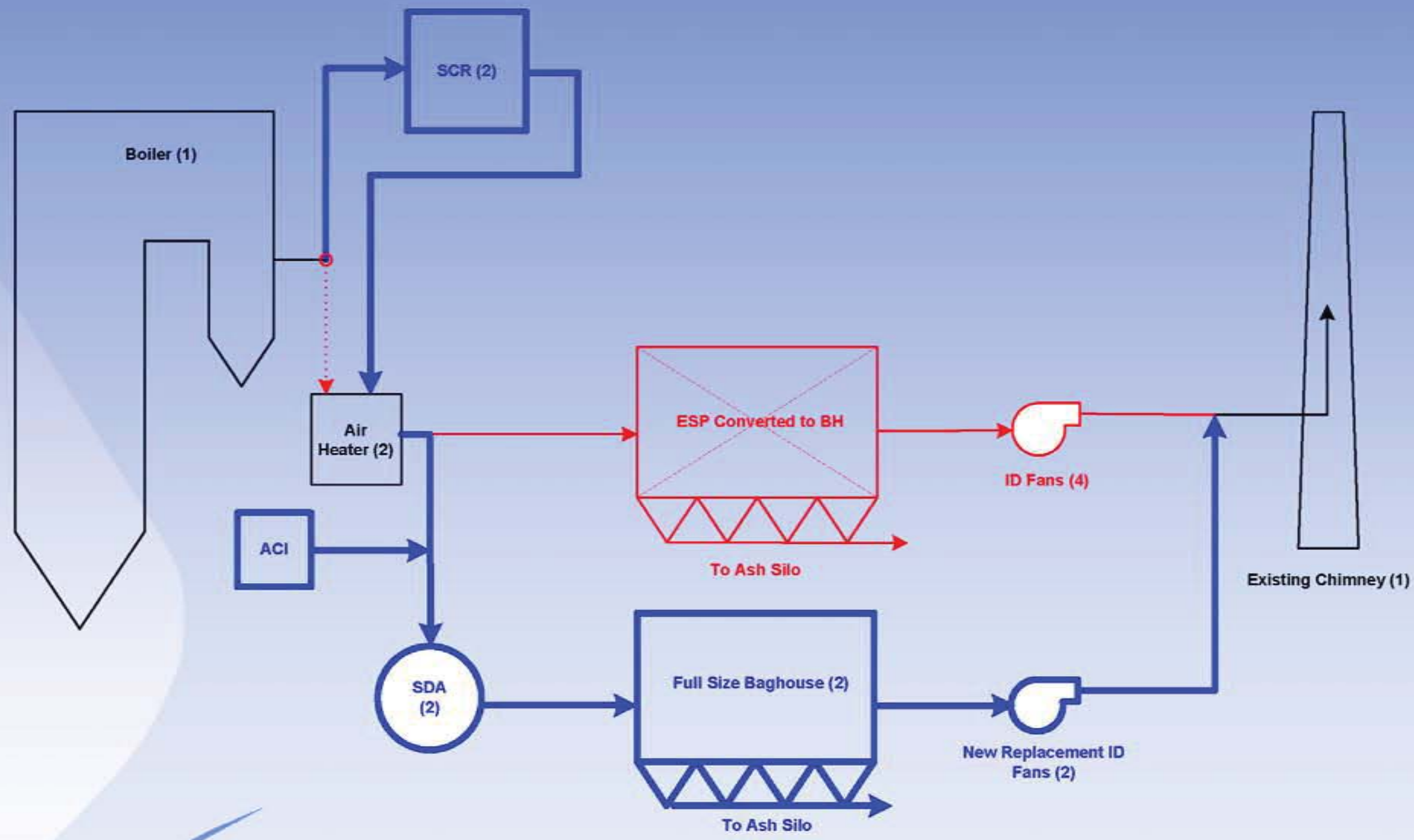
- Off-site construction road improvements, if any
- Soil remediation, if required
- Fuel costs during startup operations
- Initial fills for chemical agents and reactants (excluding the catalyst).

Assumptions / Clarifications

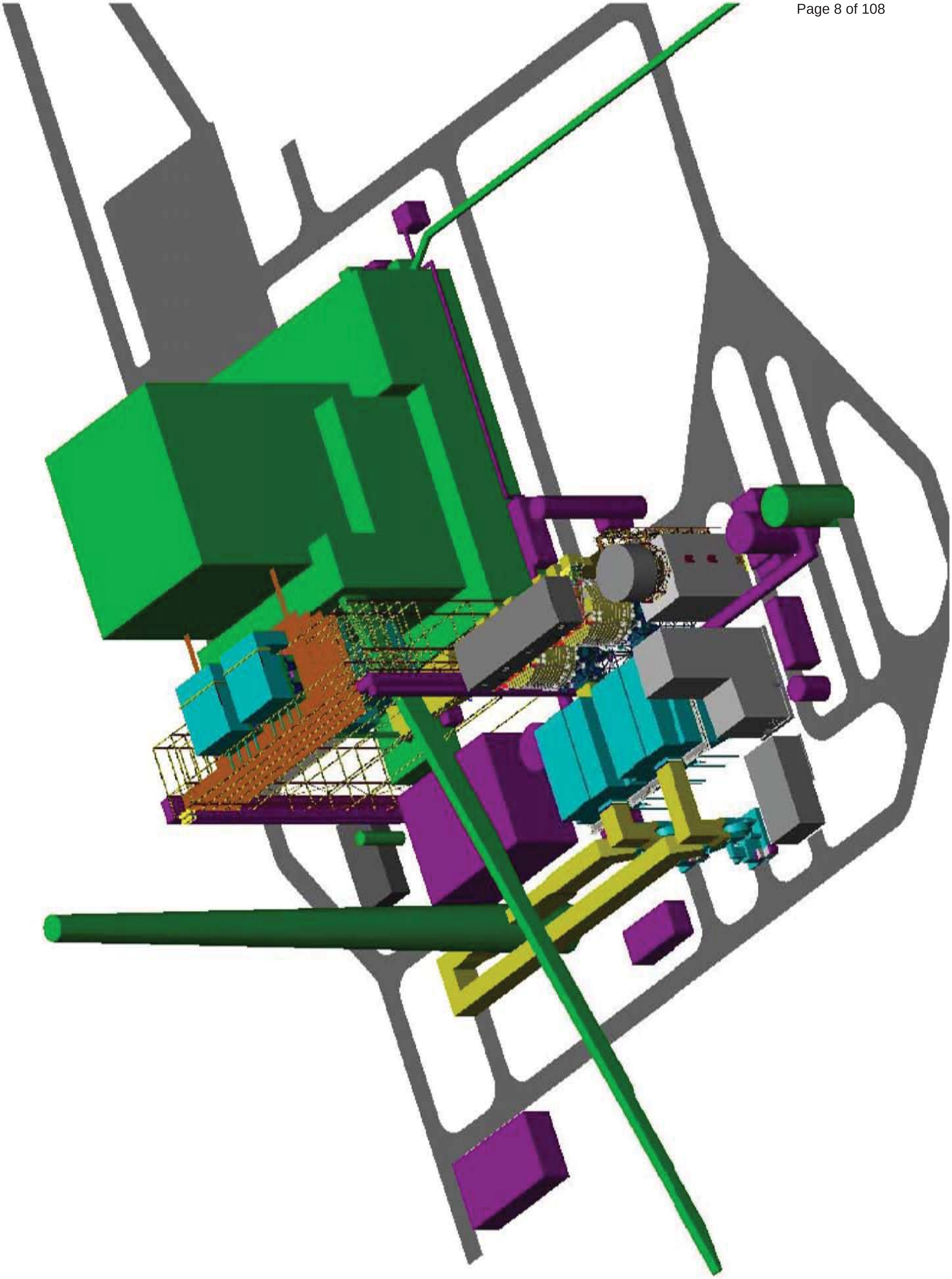
- Each cost estimate is based on the scope and general arrangements for the structures, equipment and system as described in the technical sections of the report.
- [TRADE SECRET DATA BEGINS

  TRADE SECRET DATA ENDS]
- It is assumed that no part of this project requires handling, treating or disposing of any hazardous waste or materials such as asbestos, arsenic or lead. Any hazardous material will be handled by OTP.
- The Mechanical and Electrical Balance of Plant sections included in the DFGD cost estimate account for all of the mechanical and electrical costs associated with the project in lieu of splitting scope within each area. Similarly, the Electrical Balance of Plant section of the DFGD cost estimate accounts for all of the cable, raceway costs associated with the project.
- Start up spare parts is included in the cost estimate as indirect costs.

Conceptual Design Process Flow



Sargent & Lundy LLC



Cash Flow

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

Big Stone AQCS Project

Cash Flows for November 2010 Cost Estimate

[TRADE SECRET DATA BEGINS

	Quarterly Totals	Cumulative Totals	Yearly Totals
1Q2011	$		
2Q2011	$		
3Q2011	$		
4Q2011	$		
1Q2012	$		
2Q2012	$		
3Q2012	$		
4Q2012	$		
1Q2013	$		
2Q2013	$		
3Q2013	$		
4Q2013	$		
1Q2014	$		
2Q2014	$		
3Q2014	$		
4Q2014	$		
1Q2015	$		
2Q2015	$		
3Q2015	$		
4Q2015	$		
1Q2016	$		
	$ 489,397,400		**$ 489,397,400**

TRADE SECRET DATA ENDS]

SCR Estimate

SARGENT & LUNDY

ESTIMATE NO. : 30866B
PROJECT NO. : 12715.001
ISSUE DATE : 10/29/2010
PREP/REV : JAE / MNO
APPROVED : BJD

OTTER TAIL
BIG STONE STATION
SCR
CONCEPTUAL COST ESTIMATE

[TRADE SECRET DATA BEGINS

CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
A	SCR				
A-21	CIVIL WORK				
A-21-17 Total	EARTHWORK, BACKFILL				
A-21-23 Total	EARTHWORK, EXCAVATION				
A-21-51 Total	MISCELLANEOUS				
A-21 Total	CIVIL WORK				
A-22	CONCRETE				
A-22-13 Total	CONCRETE				
A-22-15 Total	EMBEDMENT				
A-22-17 Total	FORMWORK				
A-22-21 Total	MISCELLANEOUS				
A-22-25 Total	REINFORCING				
A-22 Total	CONCRETE				
A-23	STEEL				
A-23-15 Total	DUCTWORK				
A-23-17 Total	GALLERY				
A-23-23 Total	MISCELLANEOUS				
A-23-25 Total	ROLLED SHAPE - STRUCTURAL STEEL				
A-23 Total	STEEL				
A-24	ARCHITECTURAL				
A-24-15 Total	DOOR				
A-24-37 Total	ROOFING				
A-24-41 Total	SIDING				
A-24-42 Total	PLATFORM FLOORING				
A-24 Total	ARCHITECTURAL				
A-25	STACK				
A-25-15 Total	STEEL STACK				
A-25 Total	STACK				
A-31	MECHANICAL EQUIPMENT				
A-31-13 Total	BOILER AND AIR HEATER MODIFICATIONS				
A-31-14 Total	SEPARATED OVERFIRE AIR (SOFA) SYSTEM - OPTION 2				
A-31-15 Total	BOILER COMPONENTS				
A-31-25 Total	CRANES AND HOISTS				
A-31-33 Total	EXPANSION JOINT				
A-31-53 Total	FLUE GAS CLEANUP				
A-31-73 Total	MISCELLANEOUS EQUIPMENT				
A-31-77 Total	SCREEN				
A-31-98 Total	TESTING				
A-31 Total	MECHANICAL EQUIPMENT				
A-35	PIPING				
A-35-13 Total	LARGE BORE PIPING				
A-35-15 Total	SMALL BORE PIPING				
A-35 Total	PIPING				

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

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CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
A-36	INSULATION				
A-36-13 Total	INSULATION, DUCT & EQUIPMENT				
A-36 Total	INSULATION				
A-41	ELECTRICAL EQUIPMENT				
A-41-17 Total	COMMUNICATION SYSTEM				
A-41-37 Total	LIGHTING ACCESSORY (FIXTURE)				
A-41-31 Total	GROUNDING				
A-41-35 Total	LIGHTNING PROTECTION				
A-41-41 Total	MISCELLANEOUS				
A-41-57 Total	WIRING DEVICE				
A-41 Total	ELECTRICAL EQUIPMENT				
A-42	RACEWAY, CABLE TRAY, & CONDUIT				
A-42-13 Total	CABLE TRAY				
A-42-15 Total	CONDUIT				
A-42 Total	RACEWAY, CABLE TRAY, & CONDUIT				
A-43	CABLE				
A-43-13 Total	CONTROL & INSTRUMENT CABLE				
A-43-17 Total	LOW VOLTAGE POWER CABLE & TERMINATION				
A-43 Total	CABLE				
A-44	CONTROL & INSTRUMENTATION				
A-44-21 Total	INSTRUMENT				
A-44 Total	CONTROL & INSTRUMENTATION				
A Total	SCR				
B	ANHYDROUS AMMONIA STORAGE/DELIVERY SYSTEM				
B-21	CIVIL WORK				
B-21-17 Total	EARTHWORK, BACKFILL				
B-21-23 Total	EARTHWORK, EXCAVATION				
B-21 Total	CIVIL WORK				
B-22	CONCRETE				
B-22-13 Total	CONCRETE				
B-22-15 Total	EMBEDMENT				
B-22-17 Total	FORMWORK				
B-22-25 Total	REINFORCING				
B-22 Total	CONCRETE				
B-24	ARCHITECTURAL				
B-24-33 Total	PLUMBING FIXTURES				
B-24 Total	ARCHITECTURAL				
B-31	MECHANICAL EQUIPMENT				
B-31-73 Total	MISCELLANEOUS EQUIPMENT				
B-31 Total	MECHANICAL EQUIPMENT				
B-35	PIPING				
B-35-13 Total	LARGE BORE PIPING				
B-35-15 Total	SMALL BORE PIPING				

TRADE SECRET DATA ENDS]

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CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
B-35 Total	PIPING				
B Total	ANHYDROUS AMMONIA STORAGE/DELIVERY SYSTEM				
C	MECHANICAL BOP SYSTEM IMPACTS				
C-31	MECHANICAL EQUIPMENT				
C-31-41 Total	FIRE PROTECTION EQUIPMENT & SYSTEM				
C-31 Total	MECHANICAL EQUIPMENT				
C-35	PIPING				
C-35-13 Total	LARGE BORE PIPING				
C-35 Total	PIPING				
C-44	CONTROL & INSTRUMENTATION				
C-44-21 Total	INSTRUMENT				
C-44 Total	CONTROL & INSTRUMENTATION				
C Total	MECHANICAL BOP SYSTEM IMPACTS				
D	NON POWER PRODUCING ASSETS				
D-81	NON POWER PRODUCING ASSETS				
D-81-13 Total	CONSTRUCTION EQUIPMENT				
D-81 Total	NON POWER PRODUCING ASSETS				
D Total	NON POWER PRODUCING ASSETS				
90	**SUBTOTAL DIRECT & CONSTRUCTION INDIRECT COST**				
91	OTHER DIRECT & CONSTRUCTION INDIRECT COST				
91-1	SCAFFOLDING - % of ACCT NO. 90				
91-2A	COST DUE TO OVERTIME WORKING 5-9 HOUR DAYS				
91-21A	COST DUE TO OVERTIME INEFFICIENCY - SPECIFY % INEFFICIENCY				
91-22A	COST DUE TO OVERTIME PAY @1.5 TIMES OVERTIME PAY RATE - SPECIFY % ADDITIONAL HOURS PAID ON ACTUAL HOURS WORKED				
91-23A	COST DUE TO OVERTIME - ADDITIONAL PER DIEM				
91-2B	COST DUE TO OVERTIME WORKING 7 -10 HOUR DAYS				
91-21B	COST DUE TO OVERTIME INEFFICIENCY - SPECIFY % INEFFICIENCY				
91-22B	COST DUE TO OVERTIME PAY @1.5 TIMES OVERTIME PAY RATE - SPECIFY % ADDITIONAL HOURS PAID ON ACTUAL HOURS WORKED				
91-23B	COST DUE TO OVERTIME - ADDITIONAL PER DIEM				
91-3	PER DIEM				
91-4	CONSUMABLES - % of ACCT NO. 90				
91-5	FREIGHT ON MATERIAL - % of ACCT NO. 90				
91-6	FREIGHT ON EQUIPMENT - % of ACCT NO. 90				
91-7	SALES TAX - % of ACCT NO. 90				

TRADE SECRET DATA ENDS]

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OTTER TAIL
BIG STONE STATION
SCR
CONCEPTUAL COST ESTIMATE

[TRADE SECRET DATA BEGINS

CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
91-9	CONTRACTOR'S GENERAL AND ADMINISTRATION EXPENSE - % of ACCT NO. 90				
91-10	CONTRACTOR'S PROFIT - % of ACCT NO. 90				
	91 - SUBTOTAL				
92	**TOTAL DIRECT & CONSTRUCTION INDIRECT COST**				
93	INDIRECT COST				
93-1	ENGINEERING, PROCUREMENT, & PROJECT SERVICES - % of ACCT NO. 92				
93-2	CONSTRUCTION MANAGEMENT SUPPORT - % of ACCT NO. 92				
93-3	S-U / COMMISSIONING - % of ACCT NO. 92				
93-3	START-UP SPARE PARTS				
93-4	EXCESS LIABILITY INSURANCE				
93-4	SALES TAX ON INDIRECTS				
93-5	OWNERS COST				
93-6	EPC FEE - NOT INCLUDED				
	93 - TOTAL INDIRECT COSTS				
94	TOTAL CONTINGENCY				
94-1	CONTINGENCY ON EQUIPMENT				
94-2	CONTINGENCY ON MATERIAL				
94-3	CONTINGENCY ON LABOR				
94-4	CONTINGENCY ON INDIRECT				
95	TOTAL ESCALATION				
95-1	ESCALATION ON EQUIPMENT				
95-2	ESCALATION ON MATERIAL				
95-3	ESCALATION ON LABOR				
95-4	ESCALATION ON INDIRECT				
96	**TOTAL CONSTRUCTION COST**				
97	INTEREST DURING CONSTRUCTION				
98	**TOTAL PROJECT COST**				**185,702,600**

TRADE SECRET DATA ENDS]

F:\OTTER TAIL\COST ESTIMATES\SCR\[30866B - SCR Cost Es EXCEL VERSION 062310

SARGENT & LUNDY

ESTIMATE NO. : 30866B
PROJECT NO. : 12715.001
ISSUE DATE : 10/29/2010
PREP/REV : JAE / MNO
APPROVED : BJD

[TRADE SECRET DATA BEGINS

OTTER TAIL
BIG STONE STATION
SCR
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
A	**SCR**									
A-21	CIVIL WORK									
A-21-17	EARTHWORK, BACKFILL									
A-21-17-1	EARTHWORK, BACKFILL	SCR FOUNDATION								
	A-21-17 Total									
A-21-23	EARTHWORK, EXCAVATION									
A-21-23-1	EARTHWORK, EXCAVATION	SCR FOUNDATION								
	A-21-23 Total									
A-21-51	MISCELLANEOUS									
A-21-51-1	MISCELLANEOUS	SHORING/DEWATERING SYSTEM FOR SCR FOUNDATION								
	A-21-51 Total									
	A-21 Total									
A-22	CONCRETE									
A-22-13	CONCRETE									
A-22-13-1	CONCRETE	SCR FOUNDATION								
	A-22-13 Total									
A-22-15	EMBEDMENT									
A-22-15-1	EMBEDMENT	SCR FOUNDATION								
	A-22-15 Total									
A-22-17	FORMWORK									
A-22-17-1	FORMWORK	SCR FOUNDATION								
	A-22-17 Total									
A-22-21	MISCELLANEOUS									
A-22-21-1	MISCELLANEOUS	GROUT COLUMN BASES, SCR FOUNDATION								
	A-22-21 Total									
A-22-25	REINFORCING									
A-22-25-1	REINFORCING	SCR FOUNDATION								
	A-22-25 Total									
	A-22 Total									
A-23	STEEL									
A-23-15	DUCTWORK									
A-23-15-1	DUCTWORK	GAS DUCTS BETWEEN ECONOMIZER OUTLET TO SCR, SCR DUCTWORK								
A-23-15-2	DUCTWORK	GAS DUCTS FROM SCR TO AH, SCR DUCTWORK - COR TEN B MATERIAL								

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A-23-15-3	DUCTWORK	EXISTING DUCTWORK MODIFICATIONS, SCR DUCTWORK								
A-23-15-4	DUCTWORK	2 - VESSELS (39'-6" X 47'-2" X 64' H W/HOPPER), SCR REACTOR								
A-23-15-5	DUCTWORK	ACCESS DOORS, 24"X36", SCR REACTOR								
A-23-15-6	DUCTWORK	REMOVABLE CATALYST DOOR, 6'X8', SCR REACTOR								
	A-23-15 Total									
A-23-17	GALLERY									
A-23-17-1	GALLERY	GALLERIES INCLUDING 3" HD GRATING, HR AND GUARD PLATE								
A-23-17-2	GALLERY	HD 3" DEEP GRATING INSIDE SCR REACTOR								
	A-23-17 Total									
A-23-23	MISCELLANEOUS									
A-23-23-1	BASE PLATES	SCR COLUMN BASE PLATES								
	A-23-23 Total									
A-23-25	ROLLED SHAPE - STRUCTURAL STEEL									
A-23-25-1	STRUCTURAL STEEL	SCR TOWER STEEL								
A-23-25-2	STRUCTURAL STEEL	BOILER BUILDING STEEL MODIFICATIONS - FOR SCR RELATED ONLY								
A-23-25-3	STRUCTURAL STEEL	GIRTS AND PURLINS FOR SCR PLATFORM ENCLOSURE								
	A-23-25 Total									
	A-23 Total									
A-24	ARCHITECTURAL									
A-24-15	DOOR									
A-24-15-1	DOOR	SCR PLATFORM ENCLOSURE - STEEL DOOR & FRAME, INCLUDING HARDWARE.								
	A-24-15 Total									
A-24-37	ROOFING									
A-24-37-1	ROOFING	SCR PLATFORM ENCLOSURE - UNINSULATED METAL ROOF PANELS								
	A-24-37 Total									
A-24-41	SIDING									

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A-24-41-1	SIDING	SCR PLATFORM ENCLOSURE - UNINSULATED METAL SIDING PANELS								
	A-24-41 Total									
A-24-42	PLATFORM FLOORING									
A-24-42-1	CHECKERED PLATE FLOOR	SCR PLATFORM ENCLOSURE - STEEL PLATE FLOORING - 1/4" CHECKERED PLATE								
	A-24-42 Total									
	A-24 Total									
A-25	STACK									
A-25-15	STEEL STACK									
A-25-15-1	STEEL STACK	EXTEND EXISTING 6'-6" AUXILIARY BOILER STACK BY 70 FT								
A-25-15-2	STEEL STACK	MODIFY EXISTING 6'-6" STACK - ALLOWANCE								
	A-25-15 Total									
	A-25 Total									
A-31	MECHANICAL EQUIPMENT									
A-31-13	BOILER AND AIR HEATER MODIFICATIONS									
A-31-13-1	CONVECTION PASS BOILER MODIFICATIONS FOR EEGT	INCLUDES REHEATER, PRIMARY SUPERHEATER (SMALLER PRIMARY BANK ONLY), AND V - TEMP ECONOMIZER MODS; ACCESS DOORS, STRINGER REPLACEMENT, GR INTAKE REWORK AND STRUCTURAL MODS, AND SOOTBLOWER ADDITIONS AND MODIFICATONS. SUBCONTRACT COST I								
A-31-13-2	BOILER STRUCTURAL STEEL	REINFORCMENT FOR EEGT. INCLUDED IN CONVECTION PASS BOILER MODIFICATIONS ABOVE.								
A-31-13-3	CONTROL SYSTEM SPECIFIC HARDWARE	PROGRAMMING FOR EEGT. INCLUDED IN CONVECTION PASS BOILER MODIFICATIONS ABOVE.								
	A-31-13 Total									
A-31-14	SEPARATED OVERFIRE AIR (SOFA) SYSTEM - OPTION 2									

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A-31-14-1	SOFA SYSTEM - OPTION 2	14 SOFA PORTS AND DUCT RUNS, WITH FRONT AND REAR PLENUM, PLUS PLATFORM AND STAIRWAY ADDITIONS AND MODIFICATIONS PER DWG BO172332. SUBCONTRACT COST INCLUDES EQUIPMENT, MATERIAL AND LABOR								
A-31-14-2	RE-ENTRANT THROATS	NOT INCLUDED								
A-31-14-3	MULTI-BLADE VELOCITY DAMPER ASSEMBLIES WITH AUTOMATED DRIVES.	NOT INCLUDED								
A-31-14-4	SLAG TANK VENT SYSTEM.	NOT INCLUDED								
A-31-14-5	BOILER AND A H MODIFICATIONS FOR PRESSURE INCREASE TO - 20"	INCLUDES BOILER AND AIR HEATER REINFORCEMENT.- SUBCONTRACT COST INCLUDES MATERIAL AND LABOR								
A-31-14-6	BOILER AND A H INSULATION AND LAGGING	REMOVAL AND RE-INSTALLATION - SUBCONTRACT COST INCLUDES MATERIAL AND LABOR								
A-31-14-7	DUCTWORK REMOVAL FROM ECONOMIZER OUTLET TO AIR HEATER INLET.	DEMO DUCTS FROM ECONOMIZER TO AIRHEATER - LOCATED INSIDE BLR BLDG, VERTICAL SECTION - 20' X 20' X 80' HIGH								
A-31-14-8	BOILER STRUCTURAL STEEL MODIFICATIONS.	BOILER STEEL MODIFICATIONS, DEMO, RELOCATION COL. REINFORCING, V.B. MOD.								
	A-31-14 Total									
A-31-15	BOILER COMPONENTS									
A-31-15-1	BOILER COMPONENTS	SOOTBLOWERS								
	A-31-15 Total									
A-31-25	CRANES AND HOISTS									
A-31-25-1	CRANES AND HOISTS	CATALYST REPLACEMENT TROLLY, 8 TONS								
	A-31-25 Total									
A-31-33	EXPANSION JOINT									
A-31-33-1	EXPANSION JOINT	EXPANSION JOINT								
	A-31-33 Total									
A-31-53	FLUE GAS CLEANUP									
A-31-53-1	FLUE GAS CLEANUP	CATALYST								
A-31-53-2	FLUE GAS CLEANUP	SONIC HORNS								

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	A-31-53 Total									
A-31-73	MISCELLANEOUS EQUIPMENT									
A-31-73-1	AMMONIA INJECTION GRID	AIG								
A-31-73-2	STATIC MIXER	STATIC MIXER								
A-31-73-3	PALLET TRUCKS	PALLET TRUCKS								
	A-31-73 Total									
A-31-77	SCREEN									
A-31-77-1	SCREEN	SCREEN ADDITION FOR POPCORN ASH CONTROL								
	A-31-77 Total									
A-31-98	TESTING									
A-31-98-1	TESTING	PHYSICAL AND CFD FLOW MODEL TEST. SUBCONTRACT COST								
	A-31-98 Total									
	A-31 Total									
A-35	PIPING									
A-35-13	LARGE BORE PIPING									
A-35-13-1	LARGE BORE PIPING	PIPING 2.5" CS CONDENSATE RETURN.								
A-35-13-2	LARGE BORE PIPING	PIPING 3" CS SCH 40								
A-35-13-3	LARGE BORE PIPING	PIPING 4" CS SCH 40								
A-35-13-4	LARGE BORE PIPING	PIPING, VACUUM 4" CS SCH 40								
	A-35-13 Total									
A-35-15	SMALL BORE PIPING									
A-35-15-1	SMALL BORE PIPING	INSTRUMENT AIR PIPING 2" CS, SONIC HORNS								
A-35-15-2	SMALL BORE PIPING	VALVES 2" CS, SONIC HORNS								
A-35-15-3	SMALL BORE PIPING	PIPING 2" CS SOOT BLOWER								
A-35-15-4	SMALL BORE PIPING	PIPING 2" CS HIGH PRESSURE WASH WATER, AIR HEATER MODS								
A-35-15-5	SMALL BORE PIPING	VALVES 2" SS, AIR HEATER MODS								
	A-35-15 Total									
	A-35 Total									
A-36	INSULATION									
A-36-13	INSULATION, DUCT & EQUIPMENT									
A-36-13-1	INSULATION, DUCT & EQUIPMENT	INSULATION AND LAGGING, SCR DUCTWORK								

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A-36-13-2	INSULATION, DUCT & EQUIPMENT	INSULATION AND LAGGING, SCR REACTOR								
	A-36-13 Total									
	A-36 Total									
A-41	ELECTRICAL EQUIPMENT									
A-41-17	COMMUNICATION SYSTEM									
A-41-17-1	COMMUNICATION SYSTEM	COMMUNICATIONS (PAGE PARTS AND PHONE JACKS) ALLOWANCE FOR SCR AND AMMONIA AREA								
	A-41-17 Total									
A-41-37	LIGHTING ACCESSORY (FIXTURE)									
A-41-37-1	LIGHTING ACCESSORY (FIXTURE)	FIXTURES & SUPPORT HDWR								
A-41-37-2	WIRING DEVICES	SWITCHES, RECEPTACLES								
A-41-37-3	LIGHTING CONDUIT	3/4" to 1-1/2" RGS								
A-41-37-4	LIGHTING WIRE	3/C #12 AWG 600V								
	A-41-37 Total									
A-41-31	GROUNDING									
A-41-31-1	#4/0 BARE COPPER WIRE	GROUNDING SYSTEM (FOR SCR & AMMONIA AREAS) #4/0 AWG BARE								
A-41-31-2	CADWELD	GROUNDING TERMINATION								
	A-41-31 Total									
A-41-35	LIGHTNING PROTECTION									
A-41-35-1	LIGHTNING PROTECTION	LIGHTNING PROTECTION - AIR TERMINALS, 1/2" DIA 24" LG CABLE								
	A-41-35 Total									
A-41-41	MISCELLANEOUS									
A-41-41-1	MISCELLANEOUS	ALLOWANCE FOR SOOT BLOWERS INSTALLATION								
	A-41-41 Total									
A-41-57	WIRING DEVICE									
A-41-57-1	WIRING DEVICE	WELDING RECEPTACLES 60A, 3 WIRE, 4 POLE								
A-41-57-2	WIRING DEVICES	SWITCHES, RECEPTACLES								
	A-41-57 Total									
	A-41 Total									
A-42	RACEWAY, CABLE TRAY, & CONDUIT									
A-42-13	CABLE TRAY									
A-42-13-1	12" W X 4" D AL CABLE TRAY	INCLUDING SUPPORTS & FITTINGS								

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A-42-13-1	24" W X 4" D AL CABLE TRAY	INCLUDING SUPPORTS & FITTINGS								
	A-42-13 Total									
A-42-15	CONDUIT									
A-42-15-1	3/4" RGS									
A-42-15-2	1" RGS									
A-42-15-4	1-1/2" RGS									
A-42-15-7	3/4" SEALTIGHT FLEX 3' + 2 CONNECTORS									
	A-42-15 Total									
	A-42 Total									
A-43	CABLE									
A-43-13	CONTROL & INSTRUMENT CABLE									
A-43-13-1	FIBER OPTIC CABLE									
A-43-13-2	3/C # 14									
A-43-13-3	5/C # 14									
A-43-13-4	2PR # 16 SH CHROM/CONST									
A-43-13-5	4PR # 20 AWG WIRE									
A-43-13-6	I & C CABLE & TERMINATION									
	A-43-13 Total									
A-43-17	LOW VOLTAGE POWER CABLE & TERMINATION									
A-43-17-1	3/C # 10 AWG 600V									
A-43-17-2	3/C # 6 AWG 600V									
A-43-17-3	3/C # 2 AWG 600V									
A-43-17-4	3/C # 250 MCM 600V									
A-43-17-5	600V POWER CABLE & TERMINATION									
	A-43-17 Total									
	A-43 Total									
A-44	CONTROL & INSTRUMENTATION									
A-44-21	INSTRUMENT									
A-44-21-1	AMMONIA ANALYZER	AMMONIA SLIP ANALYZER (IN SITU)								
A-44-21-2	ANALYZER ELEMENT	INSTRUMENT								
A-44-21-3	FLOW ELEMENT	INSTRUMENT								
A-44-21-4	FLOW INDICATORS	INSTRUMENT								
A-44-21-5	FLOW SWITCH	INSTRUMENT								
A-44-21-6	INDICATING LIGHT	INSTRUMENT								
A-44-21-7	LIMIT SWITCH	INSTRUMENT								
A-44-21-8	POSITION TRANSMITTER	INSTRUMENT								
A-44-21-9	PRESURE INDICATOR	INSTRUMENT								

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A-44-21-10	VACUUM/ PRESSURE SWITCH	INSTRUMENT								
A-44-21-11	PRESSURE TRANSMITTER	INSTRUMENT								
A-44-21-12	PUSHBUTTON	INSTRUMENT								
A-44-21-13	SELECTOR SWITCH	INSTRUMENT								
A-44-21-14	SOLENOID VALVE	INSTRUMENT								
A-44-21-15	TEMPERATURE ELEMENT	INSTRUMENT								
A-44-21-16	TEMPERATURE INDICATOR	INSTRUMENT								
A-44-21-17	TEMPERATURE SWITCH	INSTRUMENT								
A-44-21-18	TEMPERATURE TRANSMITTER	INSTRUMENT								
A-44-21-19	THERMOWELL	INSTRUMENT								
A-44-21-20	3/8" TUBING	INCLUDING SUPPORTS & CONNECTOR FITTINGS (ALLOWANCE)								
A-44-21-21	INSTRUMENT PANEL, RACK	INSTRUMENT RACKS								
A-44-21-22	SOOT BLOWER CONTROLS									
	A-44-21 Total									
	A-44 Total									
	A Total									
B	**ANHYDROUS AMMONIA STORAGE/DELIVERY SYSTEM**									
B-21	CIVIL WORK									
B-21-17	EARTHWORK, BACKFILL									
B-21-17-1	EARTHWORK, BACKFILL	AMMONIA TANK & PUMP, FOUNDATION & CONTAINMENT								
	B-21-17 Total									
B-21-23	EARTHWORK, EXCAVATION									
B-21-23-1	EARTHWORK, EXCAVATION	AMMONIA TANK & PUMP, FOUNDATION & CONTAINMENT								
	B-21-23 Total									
	B-21 Total									
B-22	CONCRETE									
B-22-13	CONCRETE									
B-22-13-1	CONCRETE	AMMONIA TANK & PUMP, FOUNDATION & CONTAINMENT								
B-22-13-2	CONCRETE	AMMONIA UNLOADING STATION								
	B-22-13 Total									
B-22-15	EMBEDMENT									

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B-22-15-1	EMBEDMENT	AMMONIA TANK & PUMP, FOUNDATION & CONTAINMENT								
	B-22-15 Total									
B-22-17	FORMWORK									
B-22-17-1	FORMWORK	AMMONIA TANK & PUMP, FOUNDATION & CONTAINMENT								
	B-22-17 Total									
B-22-25	REINFORCING									
B-22-25-1	REINFORCING	AMMONIA TANK & PUMP, FOUNDATION & CONTAINMENT								
	B-22-25 Total									
	B-22 Total									
B-24	ARCHITECTURAL									
B-24-33	PLUMBING FIXTURES									
B-24-33-1	PLUMBING FIXTURES	EYE WASH STATION AMMONIA AREA								
B-24-33-2	PLUMBING FIXTURES	EYE WASH STATION SCR								
	B-24-33 Total									
	B-24 Total									
B-31	MECHANICAL EQUIPMENT									
B-31-73	MISCELLANEOUS EQUIPMENT									
B-31-73-1	MISCELLANEOUS EQUIPMENT	ANHYDROUS AMMONIA STORAGE TANK, 31000 GAL. SHOP FANRICATED								
B-31-73-2	MISCELLANEOUS EQUIPMENT	AMMONIA FORWARDING PUMP SKID								
B-31-73-3	MISCELLANEOUS EQUIPMENT	VAPORIZATION SKID								
B-31-73-4	MISCELLANEOUS EQUIPMENT	DILUTION AIR SKID -INCLUDES DILUTION AIR PIPING TO AIG								
B-31-73-5	MISCELLANEOUS EQUIPMENT	CONDENSATE TANK WITH RETURN PUMPS								
B-31-73-6	MISCELLANEOUS EQUIPMENT	AMMONIA TRANSMITTERS								
B-31-73-7	MISCELLANEOUS EQUIPMENT	AMMONIA TRUCK UNLOADING STATION								
B-31-73-8	MISCELLANEOUS EQUIPMENT	MISC. CONTROLS								
B-31-73-9	MISCELLANEOUS EQUIPMENT	MISC. COSTS - FREIGHT								
	B-31-73 Total									
	B-31 Total									
B-35	PIPING									
B-35-13	LARGE BORE PIPING									

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B-35-13-1	LARGE BORE PIPING	PIPE SUPPORTS								
B-35-13-2	LARGE BORE PIPING	PIPING 8" CS								
B-35-13-3	LARGE BORE PIPING	PIPING 4" CS								
B-35-13-4	LARGE BORE PIPING	PIPING 3" CS, SERVICE AIR								
B-35-13-5	LARGE BORE PIPING	VALVES 4" SS								
	B-35-13 Total									
B-35-15	SMALL BORE PIPING									
B-35-15-1	SMALL BORE PIPING	AMMONIA INSTRUMENT AIR PIPING 2" 304 SS, AMMONIA INSTRUMENT AIR								
B-35-15-2	SMALL BORE PIPING	VALVES <1" TUBE, SS, AMMONIA INSTRUMENT AIR								
B-35-15-3	SMALL BORE PIPING	VALVES 2" SS, AMMONIA INSTRUMENT AIR								
B-35-15-4	SMALL BORE PIPING	VALVES 1" SS, SERVICE AIR								
B-35-15-5	SMALL BORE PIPING	PIPING 1" CS, SERVICE AIR								
B-35-15-6	SMALL BORE PIPING	VALVES 2" CS, SERVICE WATER								
B-35-15-7	SMALL BORE PIPING	PIPING 2" CS, SERVICE WATER								
B-35-15-8	SMALL BORE PIPING	VALVES 2" CS GALV., POTABLE WATER AMMONIA AREA								
B-35-15-9	SMALL BORE PIPING	PIPING 2" CS GALV., POTABLE WATER AMMONIA AREA								
B-35-15-10	SMALL BORE PIPING	PIPING 2", HDPE, SDR 11, DOMESTIC WATER, AMMONIA AREA								
B-35-15-11	SMALL BORE PIPING	VALVES 2" CS GALV., POTABLE WATER SCR								
B-35-15-12	SMALL BORE PIPING	PIPING 2" CS GALV., POTABLE WATER SCR								
B-35-15-13	SMALL BORE PIPING	PIPING 2" CS								
B-35-15-14	SMALL BORE PIPING	PIPING 2" CS INTERCONNECTION TO AMMONIA TANK								
	B-35-15 Total									
	B-35 Total									
	B Total									
C	**MECHANICAL BOP SYSTEM IMPACTS**									
C-31	MECHANICAL EQUIPMENT									
C-31-41	FIRE PROTECTION EQUIPMENT & SYSTEM									
C-31-41-1	FIRE PROTECTION EQUIPMENT & SYSTEM	FIRE HYDRANTS								

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	C-31-41 Total									
	C-31 Total									
C-35	PIPING									
C-35-13	LARGE BORE PIPING									
C-35-13-1	LARGE BORE PIPING	FIRE PROTECTION PIPING 6" CS SCHEDULE 40								
C-35-13-2	LARGE BORE PIPING	VALVES 6" CS PI								
C-35-13-3	LARGE BORE PIPING	4" SCH 40 CS SCR VACUUM PIPE INCLUDING FITTINGS & SUPPORTS								
C-35-13-4	LARGE BORE PIPING	6" HDPE, INCLUDES FITTINGS, UNDERGROUND, EXTEND EXISTING AND NEW FOR BH, SDA, ACI, REAGENT PREP, RECYCLE; FIRE PROTECTION								
C-35-13-5	LARGE BORE PIPING	3" CS, SCH 40, INCLUDES FITTINGS, NH3 DELUGE AND BUILDING INTERIOR, FIRE PROTECTION								
C-35-13-6	LARGE BORE PIPING	PIPE SUPPORTS FOR FIRE PROTECTION								
	C-35-13 Total									
	C-35 Total									
C-44	CONTROL & INSTRUMENTATION									
C-44-21	INSTRUMENT									
C-44-21-1	INSTRUMENT	RELOCATION OF EXISTING INSTRUMENTS AND DEVICES - ALLOWANCE								
	C-44-21 Total									
	C-44 Total									
	C Total									
D	NON POWER PRODUCING ASSETS									
D-81	NON POWER PRODUCING ASSETS									
D-81-13	CONSTRUCTION EQUIPMENT									
D-81-13-1	CONSTRUCTION EQUIPMENT	HEAVY CRANE RENTAL NOT INCLUDED IN THE WAGE RATES. INCLUDES OPREATOR AND OILER								
D-81-13-2	CONSTRUCTION EQUIPMENT	FREIGHT FOR HEAVY CRANE								
D-81-13-3	CONSTRUCTION EQUIPMENT	BUILD AND TEAR DOWN								
	D-81-13 Total									
	D-81 Total									
	D Total									

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

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APPROVED : BJD

[TRADE SECRET DATA BEGINS

OTTER TAIL
BIG STONE STATION
SCR
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
90	**SUBTOTAL DIRECT & CONSTRUCTION INDIRECT COST**									
91	OTHER DIRECT & CONSTRUCTION INDIRECT COST									
91-1	SCAFFOLDING - % of ACCT NO. 90									
91-2A	COST DUE TO OVERTIME WORKING 5-9 HOUR DAYS	95% OF BASE MANHOURS								
91-21A	COST DUE TO OVERTIME INEFFICIENCY - SPECIFY % INEFFICIENCY	95% OF BASE MANHOURS								
91-22A	COST DUE TO OVERTIME PAY @1.5 TIMES OVERTIME PAY RATE - SPECIFY % ADDITIONAL HOURS PAID ON ACTUAL HOURS WORKED									
91-23A	COST DUE TO OVERTIME - ADDITIONAL PER DIEM									
91-2B	COST DUE TO OVERTIME WORKING 7 -10 HOUR DAYS	5% OF BASE MANHOURS								
91-21B	COST DUE TO OVERTIME INEFFICIENCY - SPECIFY % INEFFICIENCY	5% OF BASE MANHOURS								
91-22B	COST DUE TO OVERTIME PAY @1.5 TIMES OVERTIME PAY RATE - SPECIFY % ADDITIONAL HOURS PAID ON ACTUAL HOURS WORKED									
91-23B	COST DUE TO OVERTIME - ADDITIONAL PER DIEM									
91-3	PER DIEM									
91-4	CONSUMABLES - % of ACCT NO. 90									
91-5	FREIGHT ON MATERIAL - % of ACCT NO. 90									
91-6	FREIGHT ON EQUIPMENT - % of ACCT NO. 90									
91-7	SALES TAX - % of ACCT NO. 90	4% SALES TAX ON EQUIPMENT, MATERIAL AND LABOR, PLUS 2% EXCISE TAX ON CONTRACTOR'S GROSS RECEIPTS EXCLUDING OWNER PURCHASED MAJOR MATERIAL WHICH ARE CALCULATED AT 4%								
91-9	CONTRACTOR'S GENERAL AND ADMINISTRATION EXPENSE - % of ACCT NO. 90									
91-10	CONTRACTOR'S PROFIT - % of ACCT NO. 90									
	91 - SUBTOTAL									
92	**TOTAL DIRECT & CONSTRUCTION INDIRECT COST**									

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

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[TRADE SECRET DATA BEGINS

OTTER TAIL
BIG STONE STATION
SCR
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
93	INDIRECT COST									
93-1	ENGINEERING, PROCUREMENT, & PROJECT SERVICES - % of ACCT NO. 92									
93-2	CONSTRUCTION MANAGEMENT SUPPORT - % of ACCT NO. 92									
93-3	S-U / COMMISSIONING - % of ACCT NO. 92									
93-3	START-UP SPARE PARTS									
93-4	EXCESS LIABILITY INSURANCE	AT 1% OF TOTAL DIRECT COST								
93-4	SALES TAX ON INDIRECTS	APPLIED SALES TAX ONLY. ASSUMED EXCISE TAX IS NOT APPLICABLE ON INDIRECTS								
93-5	OWNERS COST	INCLUDED WITH THE DRY FGD COST ESTIMATE								
93-6	EPC FEE - NOT INCLUDED									
	93 - TOTAL INDIRECT COSTS									
94	TOTAL CONTINGENCY									
94-1	CONTINGENCY ON EQUIPMENT									
94-2	CONTINGENCY ON MATERIAL									
94-3	CONTINGENCY ON LABOR									
94-4	CONTINGENCY ON INDIRECT									
95	TOTAL ESCALATION									
95-1	ESCALATION ON EQUIPMENT									
95-2	ESCALATION ON MATERIAL									
95-3	ESCALATION ON LABOR									
95-4	ESCALATION ON INDIRECT									
96	**TOTAL CONSTRUCTION COST**									
97	INTEREST DURING CONSTRUCTION	BY OTP								
98	**TOTAL PROJECT COST**									**185,702,600**

TRADE SECRET DATA ENDS]

F:\OTTER TAIL\COST ESTIMATES\SCR\[30866B - SCR Cost Estimate.xls]Detail Report EXCEL VERSION 062310

DFGD Estimate

SARGENT & LUNDY

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PREP/REV : RCK / MNO
APPROVED : BJD

OTTER TAIL
BIG STONE STATION
DFGD
CONCEPTUAL COST ESTIMATE

[TRADE SECRET DATA BEGINS

CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
A	SITE WORK				
A -21	CIVIL WORK				
A -21-13 Total	CLEARING & GRUBBING				
A -21-17 Total	EARTHWORK, BACKFILL				
A -21-23 Total	EARTHWORK, EXCAVATION				
A -21-41 Total	EROSION AND SEDIMENTATION CONTROL				
A -21-43 Total	FENCE WORK				
A -21-47 Total	LANDSCAPING				
A -21-51 Total	CIVIL WORK MISCELLANEOUS				
A -21-57 Total	ROAD, PARKING AREA, & SURFACED AREA				
A -21 Total	CIVIL WORK				
A Total	SITE WORK				
B	DRY FGD SYSTEM				
B-21	CIVIL WORK				
B-21-17 Total	EARTHWORK, BACKFILL				
B-21-23 Total	EARTHWORK, EXCAVATION				
B-21 Total	CIVIL WORK				
B-22	CONCRETE				
B-22-13 Total	CONCRETE				
B-22-15 Total	EMBEDMENT				
B-22-17 Total	FORMWORK				
B-22-25 Total	REINFORCING				
B-22 Total	CONCRETE				
B-23	STEEL				
B-23-17 Total	GALLERY				
B-23-23 Total	MISCELLANEOUS STEEL ITEMS				
B-23-25 Total	ROLLED SHAPE - STRUCTURAL STEEL				
B-23 Total	STEEL				
B-24	ARCHITECTURAL				
B-24-15 Total	DOORS				
B-24-17 Total	ELEVATOR				
B-24-25 Total	LOUVER & VENT				
B-24-33 Total	PLUMBING FIXTURES				
B-24-37 Total	ROOFING				
B-24-41 Total	SIDING				
B-24 Total	ARCHITECTURAL				
B-26	MISCELLANEOUS STRUCTURAL ITEM				
B-26-15 Total	STEEL SILO				
B-26 Total	MISCELLANEOUS STRUCTURAL ITEM				
B-27	PAINTING & COATING				
B-27-17 Total	PAINTING				
B-27 Total	PAINTING & COATING				
B-31	MECHANICAL EQUIPMENT				
B-31-41 Total	FIRE PROTECTION EQUIPMENT & SYSTEM				

TRADE SECRET DATA ENDS]

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SARGENT & LUNDY

OTTER TAIL
BIG STONE STATION
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CONCEPTUAL COST ESTIMATE

[TRADE SECRET DATA BEGINS

CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
B-31-45 Total	FLUE GAS CLEANUP, FGD EQUIPMENT				
B-31 Total	MECHANICAL EQUIPMENT				
B-33	MATERIAL HANDLING EQUIPMENT				
B-33-43 Total	PNEUMATIC HANDLING SYSTEM				
B-33-57 Total	VACUUM CLEANING SYSTEM				
B-33 Total	MATERIAL HANDLING EQUIPMENT				
B-34	HVAC				
B-34-41 Total	FANS				
B-34-53 Total	UNIT HEATER				
B-34 Total	HVAC				
B-35	PIPING				
B-35-13 Total	LARGE BORE PIPING				
B-35 Total	PIPING				
B-36	INSULATION				
B-36-13 Total	INSULATION, DUCT & EQUIPMENT				
B-36 Total	INSULATION				
B-41	ELECTRICAL EQUIPMENT				
B-41-37 Total	LIGHTING ACCESSORY (FIXTURE)				
B-41-99 Total	ELECTRICAL WORK				
B-41 Total	ELECTRICAL EQUIPMENT				
B Total	DRY FGD SYSTEM				
C	FABRIC FILTER				
C-21	CIVIL WORK				
C-21-17 Total	EARTHWORK, BACKFILL				
C-21-23 Total	EARTHWORK, EXCAVATION				
C-21 Total	CIVIL WORK				
C-22	CONCRETE				
C-22-13 Total	CONCRETE				
C-22-15 Total	EMBEDMENT				
C-22-17 Total	FORMWORK				
C-22-25 Total	REINFORCING				
C-22 Total	CONCRETE				
C-23	STEEL				
C-23-17 Total	GALLERY				
C-23-25 Total	ROLLED SHAPE - STRUCTURAL STEEL				
C-23 Total	STEEL				
C-24	ARCHITECTURAL				
C-24-37 Total	ROOFING				
C-24-41 Total	SIDING				
C-24 Total	ARCHITECTURAL				
C-27	PAINTING & COATING				
C-27-13 Total	COATING				
C-27-17 Total	PAINTING				
C-27 Total	PAINTING & COATING				

TRADE SECRET DATA ENDS]

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CONCEPTUAL COST ESTIMATE

[TRADE SECRET DATA BEGINS

CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
C-31	MECHANICAL EQUIPMENT				
C-31-41 Total	FIRE PROTECTION EQUIPMENT & SYSTEM				
C-31-57 Total	FLUE GAS CLEANUP, PARTICULATE REMOVAL EQUIPMENT				
C-31 Total	MECHANICAL EQUIPMENT				
C-33	MATERIAL HANDLING EQUIPMENT				
C-33-57 Total	VACUUM CLEANING SYSTEM				
C-33 Total	MATERIAL HANDLING EQUIPMENT				
C-35	PIPING				
C-35-13 Total	LARGE BORE PIPING				
C-35 Total	PIPING				
C-36	INSULATION				
C-36-13 Total	INSULATION, DUCT & EQUIPMENT				
C-36 Total	INSULATION				
C-41	ELECTRICAL EQUIPMENT				
C-41-37 Total	LIGHTING ACCESSORY (FIXTURE)				
C-41 Total	ELECTRICAL EQUIPMENT				
C Total	FABRIC FILTER				
D	SOLID WASTE (FGD AND FLY ASH) HANDLING SYSTEM				
D-21	CIVIL WORK				
D-21-17 Total	EARTHWORK, BACKFILL				
D-21-23 Total	EARTHWORK, EXCAVATION				
D-21 Total	CIVIL WORK				
D-22	CONCRETE				
D-22-13 Total	CONCRETE				
D-22-15 Total	EMBEDMENT				
D-22-17 Total	FORMWORK				
D-22-25 Total	REINFORCING				
D-22 Total	CONCRETE				
D-23	STEEL				
D-23-25 Total	ROLLED SHAPE - STRUCTURAL STEEL				
D-23-17 Total	GALLERY				
D-23 Total	STEEL				
D-24	ARCHITECTURAL				
D-24-33 Total	PLUMBING FIXTURES				
D-24-35 Total	PRE-ENGINEERED BUILDING				
D-24 Total	ARCHITECTURAL				
D-26	MISCELLANEOUS STRUCTURAL ITEM				
D-26-15 Total	STEEL SILO				
D-26 Total	MISCELLANEOUS STRUCTURAL ITEM				
D-33	MATERIAL HANDLING EQUIPMENT				
D-33-13 Total	ASH HANDLING EQUIPMENT				
D-33 Total	MATERIAL HANDLING EQUIPMENT				
D-41	ELECTRICAL EQUIPMENT				

TRADE SECRET DATA ENDS]

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OTTER TAIL
BIG STONE STATION
DFGD
CONCEPTUAL COST ESTIMATE

[TRADE SECRET DATA BEGINS

CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
D-41-37 Total	LIGHTING ACCESSORY (FIXTURE)				
D-41 Total	ELECTRICAL EQUIPMENT				
D Total	SOLID WASTE (FGD AND FLY ASH) HANDLING SYSTEM				
E	DUCTWORK FOR FLUE GAS SYSTEM				
E-21	CIVIL WORK				
E-21-17 Total	EARTHWORK, BACKFILL				
E-21-23 Total	EARTHWORK, EXCAVATION				
E-21 Total	CIVIL WORK				
E-22	CONCRETE				
E-22-13 Total	CONCRETE				
E-22-15 Total	EMBEDMENT				
E-22-17 Total	FORMWORK				
E-22-25 Total	REINFORCING				
E-22 Total	CONCRETE				
E-23	STEEL				
E-23-15 Total	DUCTWORK				
E-23-17 Total	GALLERY				
E-23-25 Total	ROLLED SHAPE - STRUCTURAL STEEL				
E-23 Total	STEEL				
E-31	MECHANICAL EQUIPMENT				
E-31-27 Total	DAMPERS & ACCESSORIES				
E-31-33 Total	EXPANSION JOINT				
E-31 Total	MECHANICAL EQUIPMENT				
E-36	INSULATION				
E-36-13 Total	INSULATION, DUCT & EQUIPMENT				
E-36 Total	INSULATION				
E-41	ELECTRICAL EQUIPMENT				
E-41-37 Total	LIGHTING ACCESSORY (FIXTURE)				
E-41 Total	ELECTRICAL EQUIPMENT				
E-44	CONTROL & INSTRUMENTATION				
E-44-21 Total	INSTRUMENT				
E-44 Total	CONTROL & INSTRUMENTATION				
E Total	DUCTWORK FOR FLUE GAS SYSTEM				
F	ID FANS				
F-21	CIVIL WORK				
F-21-17 Total	EARTHWORK, BACKFILL				
F-21-23 Total	EARTHWORK, EXCAVATION				
F-21 Total	CIVIL WORK				
F-22	CONCRETE				
F-22-13 Total	CONCRETE				
F-22-15 Total	EMBEDMENT				
F-22-17 Total	FORMWORK				
F-22-25 Total	REINFORCING				

TRADE SECRET DATA ENDS]

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DFGD
CONCEPTUAL COST ESTIMATE

[TRADE SECRET DATA BEGINS

CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
F-22 Total	CONCRETE				
F-31	MECHANICAL EQUIPMENT				
F-31-25 Total	CRANES & HOISTS				
F-31-27 Total	DAMPERS & ACCESSORIES				
F-31-35 Total	FANS & ACCESSORIES				
F-31 Total	MECHANICAL EQUIPMENT				
F-36	INSULATION				
F-36-13 Total	INSULATION, DUCT & EQUIPMENT				
F-36 Total	INSULATION				
F Total	ID FANS				
G	MECHANICAL - BALANCE OF PLANT				
G-21	CIVIL WORK				
G-21-17 Total	EARTHWORK, BACKFILL				
G-21-23 Total	EARTHWORK, EXCAVATION				
G-21 Total	CIVIL WORK				
G-22	CONCRETE				
G-22-13 Total	CONCRETE				
G-22-15 Total	EMBEDMENT				
G-22-17 Total	FORMWORK				
G-22-25 Total	REINFORCING				
G-22 Total	CONCRETE				
G-23	STEEL				
G-23-25 Total	ROLLED SHAPE - STRUCTURAL STEEL				
G-23 Total	STEEL				
G-31	MECHANICAL EQUIPMENT				
G-31-17 Total	COMPRESSOR & ACCESSORIES				
G-31-41 Total	FIRE PROTECTION EQUIPMENT & SYSTEM				
G-31-65 Total	HEAT EXCHANGER				
G-31-75 Total	PUMPS				
G-31-83 Total	TANKS				
G-31 Total	MECHANICAL EQUIPMENT				
G-35	PIPING				
G-35-13 Total					
G-35-15 Total					
G-35 Total	PIPING				
G-36	INSULATION				
G-36-13 Total	INSULATION, DUCT & EQUIPMENT				
G-36-15 Total	INSULATION, PIPE				
G-36 Total	INSULATION				
G-41	ELECTRICAL EQUIPMENT				
G-41-33 Total	HEAT TRACING				
G-41 Total	ELECTRICAL EQUIPMENT				
G Total	MECHANICAL - BALANCE OF PLANT				

TRADE SECRET DATA ENDS]

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[TRADE SECRET DATA BEGINS

CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
H	ELECTRICAL - AUXILIARY POWER AND BALANCE OF PLANT ELECTRICAL WORK				
H-11	DEMOLITION WORK				
H-11-41 Total	ELECTRICAL EQUIPMENT				
H-11 Total	DEMOLITION WORK				
H-21	CIVIL WORK				
H-21-17 Total	EARTHWORK, BACKFILL				
H-21-23 Total	EARTHWORK, EXCAVATION				
H-21 Total	CIVIL WORK				
H-22	CONCRETE				
H-22-13 Total	CONCRETE				
H-22-15 Total	EMBEDMENT				
H-22-17 Total	FORMWORK				
H-22-25 Total	REINFORCING				
H-22 Total	CONCRETE				
H-23	STEEL				
H-23-17 Total	GALLERY				
H-23-25 Total	STRUCTURAL STEEL				
H-23 Total	STEEL				
H-24	ARCHITECTURAL				
H-24-35 Total	PRE-ENGINEERED BUILDING				
H-24 Total	ARCHITECTURAL				
H-35	PIPING				
H-35-35 Total	PIPING				
H-35 Total	PIPING				
H-41	ELECTRICAL EQUIPMENT				
H-41-13 Total	CABLE BUS DUCT				
H-41-15 Total	CATHODIC PROTECTION				
H-41-17 Total	COMMUNICATION SYSTEM				
H-41-25 Total	FIRE DETECTION, PROTECTION				
H-41-31 Total	GROUNDING				
H-41-35 Total	LIGHTNING PROTECTION				
H-41-45 Total	MOTOR CONTROL CENTER (MCC)				
H-41-47 Total	PANEL: CONTROL, DISTRIBUTION, & RELAY				
H-41-51 Total	POWER TRANSFORMER				
H-41-55 Total	SWITCHGEAR				
H-41-53 Total	SECURITY SYSTEM				
H-41 Total	ELECTRICAL EQUIPMENT				
H-42	RACEWAY, CABLE TRAY, & CONDUIT				
H-42-13 Total	CABLE TRAY				
H-42-15 Total	CONDUITS				
H-42-17 Total	CONDUIT BOX				
H-42 Total	RACEWAY, CABLE TRAY, & CONDUIT				
H-43	CABLE				

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[TRADE SECRET DATA BEGINS

CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
H-43-13 Total	CONTROL & INSTRUMENT CABLE				
H-43-17 Total	LOW VOLTAGE POWER CABLE & TERMINATIONS				
H-43-21 Total	MEDIUM VOLTAGE POWER CABLE & TERMINATION				
H-43 Total	CABLE				
H-44	CONTROL & INSTRUMENTATION				
H-44-13 Total	CONTROL SYSTEM				
H-44-17 Total	INSTRUMENT PANEL, RACK				
H-44-21 Total	INSTRUMENT				
H-44 Total	CONTROL & INSTRUMENTATION				
H-51	SUBSTATION, SWITCHYARD & TRANSMISSION LINE				
H-51-15 Total	ELECTRICAL EQUIPMENT				
H-51-21 Total	SUBSTATION, SWITCHYARD & TRANSMISSION LINE				
H-51 Total	SUBSTATION, SWITCHYARD & TRANSMISSION LINE				
H-71	PROJECT INDIRECTS				
H-71-55 Total	VENDOR TECHNICAL ADVISORY SERVICE				
H-71 Total	PROJECT INDIRECTS				
H Total	ELECTRICAL - AUXILIARY POWER AND BALANCE OF PLANT ELECTRICAL WORK				
I	MISCELLANEOUS BUILDINGS				
I-21	CIVIL WORK				
I-21-17 Total	EARTHWORK, BACKFILL				
I-21-23 Total	EARTHWORK, EXCAVATION				
I-21 Total	CIVIL WORK				
I-22	CONCRETE				
I-22-13 Total	CONCRETE				
I-22-17 Total	FORMWORK				
I-22-25 Total	REINFORCING				
I-22 Total	CONCRETE				
I-24	ARCHITECTURAL				
I-24-31 Total	MISCELLANEOUS				
I-24-35 Total	PRE-ENGINEERED BUILDING				
I-24 Total	ARCHITECTURAL				
I Total	MISCELLANEOUS BUILDINGS				
J	REMOVAL AND RELOCATION OF EXISTING EQUIPMENT AND INFRASTRUCTURE				
J-11	DEMOLITION WORK				
J-11-22 Total	CONCRETE				
J-11-23 Total	STEEL				
J-11-26 Total	DUCTWORK				
J-11-31 Total	MECHANICAL EQUIPMENT				
J-11 Total	DEMOLITION WORK				
J-21	CIVIL WORK				
J-21-17 Total	EARTHWORK, BACKFILL				
J-21-25 Total	EARTHWORK, EXCAVATION				
J-21 Total	CIVIL WORK				

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CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
J-35	PIPING				
J-35-13 Total					
J-35 Total	PIPING				
J Total	REMOVAL AND RELOCATION OF EXISTING EQUIPMENT AND INFRASTRUCTURE				
K	NON POWER PRODUCING ASSETS				
K-81	NON POWER PRODUCING ASSETS				
K-81-13 Total	CONSTRUCTION EQUIPMENT				
K-81 Total	NON POWER PRODUCING ASSETS				
K Total	NON POWER PRODUCING ASSETS				
90	**SUBTOTAL DIRECT & CONSTRUCTION INDIRECT COST**				
91	OTHER DIRECT & CONSTRUCTION INDIRECT COST				
91-1	SCAFFOLDING - % of ACCT NO. 90				
91-2A	COST DUE TO OVERTIME WORKING 5 -9 HOUR DAYS				
91-21A	COST DUE TO OVERTIME INEFFICIENCY - SPECIFY % INEFFICIENCY				
91-22A	COST DUE TO OVERTIME PAY @1.5 TIMES OVERTIME PAY RATE - SPECIFY % ADDITIONAL HOURS PAID ON ACTUAL HOURS WORKED				
91-23A	COST DUE TO OVERTIME - ADDITIONAL PER DIEM				
91-2B	COST DUE TO OVERTIME WORKING 7 -10 HOUR DAYS				
91-21B	COST DUE TO OVERTIME INEFFICIENCY - SPECIFY % INEFFICIENCY				
91-22B	COST DUE TO OVERTIME PAY @1.5 TIMES OVERTIME PAY RATE - SPECIFY % ADDITIONAL HOURS PAID ON ACTUAL HOURS WORKED				
91-23B	COST DUE TO OVERTIME - ADDITIONAL PER DIEM				
91-3	PER DIEM				
91-4	CONSUMABLES - % of ACCT NO. 90				
91-5	FREIGHT ON MATERIAL - % of ACCT NO. 90				
91-6	FREIGHT ON EQUIPMENT - % of ACCT NO. 90				
91-7	SALES TAX - % of ACCT NO. 90				
91-9	CONTRACTOR'S GENERAL AND ADMINISTRATION EXPENSE - % of ACCT NO. 90				
91-10	CONTRACTOR'S PROFIT - % of ACCT NO. 90				
	91 - SUBTOTAL				
92	**TOTAL DIRECT & CONSTRUCTION INDIRECT COST**				
93	INDIRECT COST				
93-1	ENGINEERING, PROCUREMENT, & PROJECT SERVICES - % of ACCT NO. 92				
93-2	CONSTRUCTION MANAGEMENT SUPPORT - % of ACCT NO. 92				
93-3	S-U / COMMISSIONING - % of ACCT NO. 92				
93-3	START-UP SPARE PARTS				

TRADE SECRET DATA ENDS]

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OTTER TAIL
BIG STONE STATION
DFGD
CONCEPTUAL COST ESTIMATE

[TRADE SECRET DATA BEGINS

CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
93-4	EXCESS LIABILITY INSURANCE				
93-4	SALES TAX ON INDIRECTS				
93-5	OWNERS COST - Allowance				
93-5	OWNERS COST - 2 NEW SCRAPERS				
93-6	EPC FEE - NOT INCLUDED				
	93 - TOTAL INDIRECT COSTS				
94	**TOTAL CONTINGENCY**				
94-1	CONTINGENCY ON EQUIPMENT				
94-2	CONTINGENCY ON MATERIAL				
94-3	CONTINGENCY ON LABOR				
94-4	CONTINGENCY ON INDIRECT				
95	**TOTAL ESCALATION**				
95-1	ESCALATION ON EQUIPMENT				
95-2	ESCALATION ON MATERIAL				
95-3	ESCALATION ON LABOR				
95-4	ESCALATION ON INDIRECT				
96	TOTAL CONSTRUCTION COST				
97	INTEREST DURING CONSTRUCTION				
98	**TOTAL PROJECT COST**				**303,694,800**

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CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
A	**SITE WORK**									
A -21	**CIVIL WORK**									
A -21-13	CLEARING & GRUBBING									
A -21-13-1	CLEARING & GRUBBING	CUT AND STRIP TOPSOIL 6", LAYDOWN AREA								
A -21-13-2	CLEARING & GRUBBING	TOPSOIL STORAGE STOCKPILE (ASSUMES ON SITE STOCKPILING), LAYDOWN AREA								
A -21-13-3	CLEARING & GRUBBING	CUT AND STRIP TOPSOIL, INTERIOR PLANT ROADS AND SURFACING								
	A -21-13 Total									
A -21-17	EARTHWORK, BACKFILL									
A -21-17-1	EARTHWORK, BACKFILL	FILL, INTERIOR PLANT ROADS AND SURFACING								
	A -21-17 Total									
A -21-23	EARTHWORK, EXCAVATION									
A -21-23-1	EARTHWORK, EXCAVATION	CUT, INTERIOR PLANT ROADS AND SURFACING								
	A -21-23 Total									
A -21-41	EROSION AND SEDIMENTATION CONTROL									
A -21-41-1	EROSION AND SEDIMENTATION CONTROL	SILT FENCE, TOTAL FOR STOCKPILE AND LAYDOWN AREA								
	A -21-41 Total									
A -21-43	FENCE WORK									
A -21-43-1	FENCE WORK	FENCING WITH ONE 3-STRAND BARBED WIRE UNIT, FABRIC, POSTS ON 10FT CENTERS, LAYDOWN AREA								
A -21-43-2	FENCE WORK	GATES 50FT WIDE DOUBLE SWING, LAYDOWN AREA								
	A -21-43 Total									
A -21-47	LANDSCAPING									
A -21-47-1	LANDSCAPING	GRASS SEEDING OVER STOCKPILE AREA, LAYDOWN AREA								
A -21-47-2	LANDSCAPING	PLACE TOPSOIL - PREVIOUSLY STOCKPILED, RESTORATION OF DISTURBED AREA								
A -21-47-3	LANDSCAPING	GRASS SEEDING - MULCH AND FERTILIZER, RESTORATION OF LAYDOWN AREA								

TRADE SECRET DATA ENDS]

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	A -21-47 Total									
A -21-51	CIVIL WORK MISCELLANEOUS									
A -21-51-1	CIVIL WORK MISCELLANEOUS	GEOTEXTILE MEMBRANE 10 oz/sy, LAYDOWN AREA								
A -21-51-2	CIVIL WORK MISCELLANEOUS	GEOTEXTILE MEMBRANE 10 oz/sy, INTERIOR PLANT ROADS AND SURFACING								
A -21-51-3	CIVIL WORK MISCELLANEOUS	GEOTEXTILE MEMBRANE 10 oz/sy ENTIRE AREA, INTERIOR PLANT ROADS AND SURFACING								
	A -21-51 Total									
A -21-57	ROAD, PARKING AREA, & SURFACED AREA									
A -21-57-1	AGGREGATE SURFACING	AGGREGATE SURFACING 4" THICK OVER ENTIRE AREA, LAYDOWN AREA								
A -21-57-2	AGGREGATE SURFACING	AGGREGATE SURFACING 6" THICK OVER ENTIRE AREA, INTERIOR PLANT ROADS AND SURFACING								
A -21-57-3	CONCRETE ROAD	CONCRETE ROAD 9" THICK, 24FT W X 2600 L, INTERIOR PLANT ROADS AND SURFACING								
A -21-57-4	AGGREGATE SURFACING	CONTRACTOR TRAILER AREA SURFACING INCLUDES : 9" AGGREGATE SURFACING, 12" SUBGRADE PREP, INTERIOR PLANT ROADS AND SURFACING								
	A -21-57 Total									
	A -21 Total									
	A Total									
B	**DRY FGD SYSTEM**									
B-21	**CIVIL WORK**									
B-21-17	EARTHWORK, BACKFILL									
B-21-17-1	EARTHWORK, BACKFILL	SDA FOUNDATION								
B-21-17-2	EARTHWORK, BACKFILL	LIME SILO & REAGENT PREP BUILDING, 45'X60'								
B-21-17-3	EARTHWORK, BACKFILL	REAGENT PREP BUILDING, STAIR TOWER								
B-21-17-4	EARTHWORK, BACKFILL	RECYCLE BUILDING, 80'X40'								
B-21-17-5	EARTHWORK, BACKFILL	SLURRY BASIN FOUNDATION								
	B-21-17 Total									
B-21-23	EARTHWORK, EXCAVATION									

TRADE SECRET DATA ENDS]

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CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
B-21-23-1	EARTHWORK, EXCAVATION	SDA FOUNDATION								
B-21-23-2	EARTHWORK, EXCAVATION	LIME SILO & REAGENT PREP BUILDING, 45'X60'								
B-21-23-3	EARTHWORK, EXCAVATION	REAGENT PREP BUILDING, STAIR TOWER								
B-21-23-4	EARTHWORK, EXCAVATION	RECYCLE BUILDING, 80'X40'								
B-21-23-5	EARTHWORK, EXCAVATION	SLURRY BASIN FOUNDATION								
	B-21-23 Total									
	B-21 Total									
B-22	**CONCRETE**									
B-22-13	CONCRETE									
B-22-13-1	CONCRETE	CONCRETE PIT FOR THE ELEVATOR, LIME SILO (NOT INCLUDED)								
B-22-13-2	CONCRETE	SDA FOUNDATION								
B-22-13-3	CONCRETE	FLOOR SLAB FOR COMMON SDA PENTHOUSE, INCLUDES METAL DECKING AND FORMWORK								
B-22-13-4	CONCRETE	FOUNDATION FOR THE ELEVATOR (W/100#/CY REBAR), SDA SUPERSTRUCTURE								
B-22-13-5	CONCRETE	LIME SILO & REAGENT PREP BUILDING, 45'X60'								
B-22-13-6	CONCRETE	REAGENT PREP BUILDING, STAIR TOWER								
B-22-13-7	CONCRETE	RECYCLE BUILDING, 80'X40'								
B-22-13-8	CONCRETE	LIGHT WEIGHT CONCRETE FILL 1", RECYCLE BUILDING								
B-22-13-9	CONCRETE	FLOOR SLABS INCLUDES METAL DECKING AND FORMWORK, LIME SLURRY PREPARATION / RECYCLE BUILDING								
B-22-13-10	CONCRETE	SLURRY BASIN FOUNDATION								
	B-22-13 Total									
B-22-15	EMBEDMENT									
B-22-15-1	EMBEDMENT	SDA FOUNDATION								
B-22-15-2	EMBEDMENT	LIME SILO & REAGENT PREP BUILDING, 45'X60'								
B-22-15-3	EMBEDMENT	REAGENT PREP BUILDING, STAIR TOWER								
B-22-15-4	EMBEDMENT	RECYCLE BUILDING, 80'X40'								

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B-22-15-5	EMBEDMENT	SLURRY BASIN FOUNDATION								
	B-22-15 Total									
B-22-17	FORMWORK									
B-22-17-1	FORMWORK	SDA FOUNDATION								
B-22-17-2	FORMWORK	LIME SILO & REAGENT PREP BUILDING, 45'X60'								
B-22-17-3	FORMWORK	RECYCLE BUILDING, 80'X40'								
B-22-17-4	FORMWORK	SLURRY BASIN FOUNDATION								
	B-22-17 Total									
B-22-25	REINFORCING									
B-22-25-1	REINFORCING	SDA FOUNDATION								
B-22-25-2	REINFORCING	LIME SILO & REAGENT PREP BUILDING, 45'X60'								
B-22-25-3	REINFORCING	REAGENT PREP BUILDING, STAIR TOWER								
B-22-25-4	REINFORCING	RECYCLE BUILDING, 80'X40'								
B-22-25-5	REINFORCING	SLURRY BASIN FOUNDATION								
	B-22-25 Total									
	B-22 Total									
B-23	**STEEL**									
B-23-17	GALLERY									
B-23-17-1	GALLERY	ACCESS GALLERY, SDA								
B-23-17-2	GALLERY	REAGENT HANDLING / PREPARATION								
B-23-17-3	GALLERY	STAIR TOWER 10'X25'X120' H, REAGENT PREP BUILDING								
B-23-17-4	GALLERY	GALLERIES AND LANDINGS, RECYCLE BUILDING								
B-23-17-5	GALLERY	MISCELLANEOUS GALLERIES, SLURRY BASIN								
	B-23-17 Total									
B-23-23	MISCELLANEOUS STEEL ITEMS									
B-23-23-1	MISCELLANEOUS STEEL ITEMS	METAL ROOF DECKING, RECYCLE BUILDING								
	B-23-23 Total									
B-23-25	ROLLED SHAPE - STRUCTURAL STEEL									
B-23-25-1	ROLLED SHAPE - STRUCTURAL STEEL	STEEL STRUCTURE FOR COMMON PENTHOUSE FOR SDA'S (50'X140'X20'); INCLUDED IN DFGD SYSTEM PRICE								

TRADE SECRET DATA ENDS]

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B-23-25-2	ROLLED SHAPE - STRUCTURAL STEEL	SUPPORT STEEL, SDA - MATERIAL IS INCLUDED IN DFGD SYSTEM PRICE								
B-23-25-3	ROLLED SHAPE - STRUCTURAL STEEL	ADDITIONAL SUPPORT STEEL TO RAISE SDA'S 20FT								
B-23-25-4	ROLLED SHAPE - STRUCTURAL STEEL	LIME SILO & REAGENT PREP BUILDING, 45'X60'								
B-23-25-5	ROLLED SHAPE - STRUCTURAL STEEL	REAGENT PREP BUILDING, STAIR TOWER								
B-23-25-6	ROLLED SHAPE - STRUCTURAL STEEL	SUPPORT STEEL FOR RECYCLE STORAGE SILO, RECYCLE BUILDING (40'X80'X125'H)								
	B-23-25 Total									
	B-23 Total									
B-24	**ARCHITECTURAL**									
B-24-15	DOORS									
B-24-15-1	DOORS	ROLLING OVERHEAD DOORS FOR LIME SILO & REAGENT PREP BUILDING & RECYCLE BUILDING								
	B-24-15 Total									
B-24-17	ELEVATOR									
B-24-17-1	ELEVATOR	TO SDA AND SCR - SIX PERSON RACK AND PINION ELEVATOR, SUBCONTRACT PRICE INCLUDES LABOR								
	B-24-17 Total									
B-24-25	LOUVER & VENT									
B-24-25-1	LOUVER & VENT	LIME SILO & REAGENT PREP BUILDING								
B-24-25-2	LOUVER & VENT	RECYCLE BUILDING	1,							
	B-24-25 Total									
B-24-33	PLUMBING FIXTURES									
B-24-33-1	PLUMBING FIXTURES	EYEWASH STATION AND SHOWER, LIME SILO & REAGENT PREP BUILDING, W 50 KW HTRS								
B-24-33-2	PLUMBING FIXTURES	EYEWASH STATION AND SHOWER, RECYCLE BUILDING , W 50 KW HTRS								
	B-24-33 Total									
B-24-37	ROOFING									

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B-24-37-1	ROOFING	SDA ROOF INSULATION BETWEEN PENTHOUSE FLOOR AND SDA ROOF TOTAL FOR 2 SDA'S								
B-24-37-2	ROOFING	COMMON SDA PENTHOUSE, STANDING SEAM TYPE								
B-24-37-3	ROOFING	RIGID ROOF INSULATION, 2" THICK, RECYCLE BUILDING								
B-24-37-4	ROOFING	ROOFING (4-PLY TAR & GRAVEL), RECYCLE BUILDING								
B-24-37-5	ROOFING	ROOF FLASHING, RECYCLE BUILDING								
B-24-37-6	ROOFING	REAGENT PREP BUILDING - STANDING SEAM TYPE								
	B-24-37 Total									
B-24-41	SIDING									
B-24-41-1	SIDING	INSULATED METAL SIDING, COMMON SDA PENTHOUSE								
B-24-41-2	SIDING	INSULATED SIDING FOR SDA HOPPER ENCLOSURE, SDA								
B-24-41-3	SIDING	INSULATED METAL SIDING, RECYCLE BUILDING								
B-24-41-4	SIDING	LIME SILO & REAGENT PREP BUILDING, 45'X60'								
	B-24-41 Total									
	B-24 Total									
B-26	**MISCELLANEOUS STRUCTURAL ITEM**									
B-26-15	STEEL SILO									
B-26-15-1	STEEL SILO	LIME STORAGE SILO 600 TN CAPACITY								
	B-26-15 Total									
	B-26 Total									
B-27	**PAINTING & COATING**									
B-27-17	PAINTING									
B-27-17-1	PAINTING	TOUCH-UP PAINTING SDA SUPPORT STEEL AND ACCESS GALLERIES								
	B-27-17 Total									
	B-27 Total									
B-31	**MECHANICAL EQUIPMENT**									
B-31-41	FIRE PROTECTION EQUIPMENT & SYSTEM									
B-31-41-1	FIRE PROTECTION EQUIPMENT	STANDPIPE AND HOSE STATION, ABSORBER AREA								

TRADE SECRET DATA ENDS]

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B-31-41-2	FIRE PROTECTION EQUIPMENT	STANDPIPE & HOSE STATION, SDA PENTHOUSE								
B-31-41-3	FIRE PROTECTION EQUIPMENT	STANDPIPE & HOSE STATION, LIME SILO & REAGENT PREP BUILDING, 45'X60'								
B-31-41-4	FIRE PROTECTION EQUIPMENT	STANDPIPE & HOSE STATION, RECYCLE BUILDING								
	B-31-41 Total									
B-31-45	FLUE GAS CLEANUP, FGD EQUIPMENT									
B-31-45-1	DRY FGD SYSTEM	DRY FGD SYSTEM								
B-31-45-2	DRY FGD SYSTEM	SPRAY DRYERS, ATOMIZERS, HEAD TANK, PENTHOUSE AND OTHER ANCILLARY EQUIPMENT INCLUDING SPARE ATOMIZER, ABSORBER AREA - INCLUDED IN DFGD SYSTEM PRICE								
B-31-45-3	DRY FGD SYSTEM	DUMPSTER, UNDER SDA HOPPER, ABSORBER AREA								
B-31-45-4	DRY FGD SYSTEM	REAGENT HANDLING / PREPARATION - MECHANICAL - INCLUDED IN DFGD SYSTEM PRICE								
B-31-45-5	DRY FGD SYSTEM	REAGENT PREP PROCESS EQUIPMENT - INCLUDED IN DFGD SYSTEM PRICE								
B-31-45-6	DRY FGD SYSTEM	SLAKERS THROUGH THE LIME SLURRY STORAGE TANKS, PUMPS, GRIT CONVEYORS AND ANY OTHER ANCILLARY SYSTEMS - INCLUDED IN DFGD SYSTEM PRICE								
B-31-45-7	DRY FGD SYSTEM	ASH RECYCLING SYSTEM; BLOWERS, FEEDERS, SLURRY MIX TANKS, AGITATORS AND FEED PUMPS. (4 HOUR SILO INCLUDED IN VENDOR QUOTE) - INCLUDED IN DFGD SYSTEM PRICE								
B-31-45-8	DRY FGD SYSTEM	PIPING & VALVES TO CONVEY RECYCLED ASH TO RECYCLE BIN								
B-31-45-9	FLOW STUDY	INCLUDED IN VENDORS PROPOSAL								
	B-31-45 Total									
	B-31 Total									

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B-33	**MATERIAL HANDLING EQUIPMENT**									
B-33-43	PNEUMATIC HANDLING SYSTEM									
B-33-43-1	PNEUMATIC HANDLING SYSTEM	PNEUMATIC LIME TRUCK UNLOADING EQUIPMENT/PIPING TO LIME STORAGE SILO								
	B-33-43 Total									
B-33-57	VACUUM CLEANING SYSTEM									
B-33-57-1	VACUUM CLEANING SYSTEM	VACUUM CLEANING SYSTEM, ONE HEADER LENGTH OF PENTHOUSE AND PIPE DOWN TO GRADE - INCLUDES MISC HOSE CONNECTIONS WITH TRUCK HOOK UP AND PURCHASED STUB ENDS. PIPING IS INCLUDED IN ACCOUNT C-35-13-1								
	B-33-57 Total									
	B-33 Total									
B-34	**HVAC**									
B-34-41	FANS									
B-34-41-1	FANS	ROOF VENTILATORS, LIME SILO & REAGENT PREP BUILDING								
B-34-41-2	FANS	ROOF VENTILATORS, RECYCLE BUILDING								
	B-34-41 Total									
B-34-53	UNIT HEATER									
B-34-53-1	STEAM UNIT HEATER - WALL MOUNT, 150,000 BTU EA	H & V, RECYCLE BUILDING. INCLUDES 2 UNIT HEATERS AND 400 FT PIPING ALLOWANCE								
B-34-53-2	STEAM UNIT HEATER - WALL MOUNT, 150,000 BTU EA	LIME SILO & REAGENT PREP BUILDING, 45'X60' INCLUDES 2 UNIT HEATERS AND 400 FT PIPING ALLOWANCE								
B-34-53-3	STEAM UNIT HEATER - WALL MOUNT, 150,000 BTU EA	SDA, INCLUDES 4 UNIT HEATERS AND 700 FT PIPING ALLOWANCE								
	B-34-53 Total									
	B-34 Total									
B-35	**PIPING**									
B-35-13	LARGE BORE PIPING									
B-35-13-1	LARGE BORE PIPING	ROOF DRAINS, LIME SILO & REAGENT PREP BUILDING								

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B-35-13-2	LARGE BORE PIPING	ROOF DRAINS, RECYCLE BUILDING								
B-35-13-3	LARGE BORE PIPING	FLOOR DRAINS, LIME SILO & REAGENT PREP BUILDING								
B-35-13-4	LARGE BORE PIPING	FLOOR DRAINS, RECYCLE BUILDING								
B-35-13-5	LARGE BORE PIPING	4" SCH 40 CS BH VACUUM PIPE INCLUDING FITTINGS & SUPPORTS								
	B-35-13 Total									
	B-35 Total									
B-36	**INSULATION**									
B-36-13	INSULATION, DUCT & EQUIPMENT									
B-36-13-1	INSULATION, DUCT & EQUIPMENT	SHELL INSULATION, SUBCONTRACT COST, SDA								
	B-36-13 Total									
	B-36 Total									
B-41	**ELECTRICAL EQUIPMENT**									
B-41-37	LIGHTING ACCESSORY (FIXTURE)									
B-41-37-1	LIGHTING ACCESSORY (FIXTURE)	ELECTRICAL SERVICE & LIGHTING, SDA SUPERSTRUCTURE								
B-41-37-2	LIGHTING ACCESSORY (FIXTURE)	ELECTRICAL SERVICE & LIGHTING, LIME SILO & REAGENT PREP BUILDING								
B-41-37-3	LIGHTING ACCESSORY (FIXTURE)	ELECTRICAL SERVICE & LIGHTING, RECYCLE BUILDING								
	B-41-37 Total									
B-41-99	ELECTRICAL WORK									
B-41-99-1	ELECTRICAL WORK	ELECTRICAL WORK FOR THE ELEVATOR, SDA								
	B-41-99 Total									
	B-41 Total									
	B Total									
C	**FABRIC FILTER**									
C-21	**CIVIL WORK**									
C-21-17	EARTHWORK, BACKFILL									
C-21-17-1	EARTHWORK, BACKFILL	FABRIC FILTER BAGHOUSE FOUNDATION								
	C-21-17 Total									
C-21-23	EARTHWORK, EXCAVATION									
C-21-23-1	EARTHWORK, EXCAVATION	FABRIC FILTER BAGHOUSE FOUNDATION								

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OTTER TAIL
BIG STONE STATION
DFGD
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
	C-21-23 Total									
	C-21 Total									
C-22	**CONCRETE**									
C-22-13	CONCRETE									
C-22-13-1	CONCRETE	CONCRETE FLOOR SLAB FOR BAGHOUSE PENTHOUSE (NOT INCLUDED)								
C-22-13-2	CONCRETE	FABRIC FILTER BAGHOUSE FOUNDATION								
	C-22-13 Total									
C-22-15	EMBEDMENT									
C-22-15-1	EMBEDMENT	FABRIC FILTER BAGHOUSE FOUNDATION								
	C-22-15 Total									
C-22-17	FORMWORK									
C-22-17-1	FORMWORK	FABRIC FILTER BAGHOUSE FOUNDATION								
	C-22-17 Total									
C-22-25	REINFORCING									
C-22-25-1	REINFORCING	FABRIC FILTER BAGHOUSE FOUNDATION								
	C-22-25 Total									
	C-22 Total									
C-23	**STEEL**									
C-23-17	GALLERY									
C-23-17-1	GALLERY	FABRIC FILTER BAGHOUSE - INCLUDED IN FABRIC FILTER SYSTEM								
	C-23-17 Total									
C-23-25	ROLLED SHAPE - STRUCTURAL STEEL									
C-23-25-1	ROLLED SHAPE - STRUCTURAL STEEL	HOPPER ENCLOSURE SUPPORT STEEL, GIRTS AND PURLINS								
C-23-25-2	ROLLED SHAPE - STRUCTURAL STEEL	FABRIC FILTER BAGHOUSE - MATERIAL IS INCLUDED IN FABRIC FILTER SYSTEM								
	C-23-25 Total									
	C-23 Total									
C-24	**ARCHITECTURAL**									
C-24-37	ROOFING									

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PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

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C-24-37-1	ROOFING	ROOFING FOR BAGHOUSE PENTHOUSE INCLUDING 2" OF INSULATION, STANDING SEAM TYPE. TOTAL FOR 2 BAGHOUSE STRUCTURES								
	C-24-37 Total									
C-24-41	SIDING									
C-24-41-1	SIDING	INSULATED METAL SIDING FOR BAGHOUSE PENTHOUSE, 2" THICK INSULATION								
C-24-41-2	SIDING	SIDING FOR BAGHOUSE HOPPER ENCLOSURE INCLUDING 2" INSULATION								
	C-24-41 Total									
	C-24 Total									
C-27	**PAINTING & COATING**									
C-27-13	COATING									
C-27-13-1	COATING	INTERNAL COATING; 12,800 SF, AROUND DOORS AND OPENINGS, 25 MILS DFT FLUEGARD. SUBCONTRACT COST INCLUDES MATERIAL AND LABOR.								
	C-27-13 Total									
C-27-17	PAINTING									
C-27-17-1	PAINTING	TOUCH-UP PAINTING, FABRIC FILTER BAGHOUSE								
	C-27-17 Total									
	C-27 Total									
C-31	**MECHANICAL EQUIPMENT**									
C-31-41	FIRE PROTECTION EQUIPMENT & SYSTEM									
C-31-41-1	FIRE PROTECTION EQUIPMENT & SYSTEM	FIRE PROTECTION FOR PENTHOUSE, STANDPIPE & HOSE STATION								
C-31-41-2	FIRE PROTECTION EQUIPMENT & SYSTEM	FIRE PROTECTION FOR HOPPER ENCLOSURE, STANDPIPE & HOSE STATION								
	C-31-41 Total									
C-31-57	FLUE GAS CLEANUP, PARTICULATE REMOVAL EQUIPMENT									

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PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
C-31-57-1	FLUE GAS CLEANUP, PARTICULATE REMOVAL EQUIPMENT	FABRIC FILTER SYSTEM INCLUDING BYPASS, DAMPERS, HOPPER HEATERS, VENT FAN, HOIST AND TROLLEY BEAM, PENTHOUSE SUPERSTRUCTURE W/ 8 COMPARTMENTS.(EXCLUDES AIR COMPRESSORS - USE EXISTING)								
	C-31-57 Total									
	C-31 Total									
C-33	**MATERIAL HANDLING EQUIPMENT**									
C-33-57	VACUUM CLEANING SYSTEM									
C-33-57-1	VACUUM CLEANING SYSTEM	VACUUM CLEANING SYSTEM, ONE HEADER LENGTH OF PENTHOUSE AND PIPE DOWN TO GRADE - INCLUDES MISC HOSE CONNECTIONS WITH TRUCK HOOK UP AND PURCHASED STUB ENDS. PIPING IS INCLUDED IN ACCOUNT C-35-13-1								
	C-33-57 Total									
	C-33 Total									
C-35	**PIPING**									
C-35-13	LARGE BORE PIPING									
C-35-13-1	LARGE BORE PIPING	4" SCH 40 CS BH VACUUM PIPE INCLUDING FITTINGS & SUPPORTS								
C-35-13-2	LARGE BORE PIPING	3" SCH 40 CS BH CLEAN AIR PIPING INCLUDING FITTINGS & HOSES & SUPPORTS								
	C-35-13 Total									
	C-35 Total									
C-36	**INSULATION**									
C-36-13	INSULATION, DUCT & EQUIPMENT									
C-36-13-1	INSULATION, DUCT & EQUIPMENT	INSULATION FOR FABRIC FILTER BAGHOUSE 6" THICK, SUBCONTRACT COST INCLUDES MATERIAL AND LABOR								
	C-36-13 Total									
	C-36 Total									
C-41	**ELECTRICAL EQUIPMENT**									
C-41-37	LIGHTING ACCESSORY (FIXTURE)									

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C-41-37-1	LIGHTING ACCESSORY (FIXTURE)	BUILDING SERVICES, H&V AND LIGHTING, FABRIC FILTER BAGHOUSE PENTHOUSE AND HOPPER SKIRTS ENCLOSURES								
	C-41-37 Total									
	C-41 Total									
	C Total									
D	**SOLID WASTE (FGD AND FLY ASH) HANDLING SYSTEM**									
D-21	**CIVIL WORK**									
D-21-17	EARTHWORK, BACKFILL									
D-21-17-1	EARTHWORK, BACKFILL	FOUNDATION, SOLID WASTE SILO								
D-21-17-2	EARTHWORK, BACKFILL	WASTE BLOWER BUILDING FOUNDATION								
	D-21-17 Total									
D-21-23	EARTHWORK, EXCAVATION									
D-21-23-1	EARTHWORK, EXCAVATION	FOUNDATION, SOLID WASTE SILO								
D-21-23-2	EARTHWORK, EXCAVATION	WASTE BLOWER BUILDING FOUNDATION								
	D-21-23 Total									
	D-21 Total									
D-22	**CONCRETE**									
D-22-13	CONCRETE									
D-22-13-1	CONCRETE	FOUNDATION, SOLID WASTE SILO								
D-22-13-2	CONCRETE	WASTE BLOWER BUILDING FOUNDATION								
	D-22-13 Total									
D-22-15	EMBEDMENT									
D-22-15-1	EMBEDMENT	FOUNDATION, SOLID WASTE SILO								
D-22-15-2	EMBEDMENT	WASTE BLOWER BUILDING FOUNDATION								
	D-22-15 Total									
D-22-17	FORMWORK									
D-22-17-1	FORMWORK	FOUNDATION, SOLID WASTE SILO								
D-22-17-2	FORMWORK	WASTE BLOWER BUILDING FOUNDATION								
	D-22-17 Total									

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CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
D-22-25	REINFORCING									
D-22-25-1	REINFORCING	FOUNDATION, SOLID WASTE SILO								
D-22-25-2	REINFORCING	WASTE BLOWER BUILDING FOUNDATION								
	D-22-25 Total									
	D-22 Total									
D-23	**STEEL**									
D-23-25	ROLLED SHAPE - STRUCTURAL STEEL									
D-23-25-1	ROLLED SHAPE - STRUCTURAL STEEL	ADDITIONAL SUPPORT STEEL FOR WASTE ASH PIPES OUTSIDE OF PIPE RACK, WASTE BLOWER BUILDING								
	D-23-25 Total									
D-23-17	GALLERY									
D-23-17-1	GALLERY	STAIR TOWER FOR WASTE ASH SILO (10'X15'X80')								
D-23-17-2	GALLERY	WASTE ASH SILO								
	D-23-17 Total									
	D-23 Total									
D-24	**ARCHITECTURAL**									
D-24-33	PLUMBING FIXTURES									
D-24-33-1	PLUMBING FIXTURES	EYEWASH STATION AND SHOWER, REAGENT (LIME AND RECYCLE) BUILDING , W 50 KW HTRS								
	D-24-33 Total									
D-24-35	PRE-ENGINEERED BUILDING									
D-24-35-1	PRE-ENGINEERED BUILDING	(30'X60'X20' H) INCLUDES H&V AND LIGHTING, WASTE BLOWER BUILDING								
	D-24-35 Total									
	D-24 Total									
D-26	**MISCELLANEOUS STRUCTURAL ITEM**									
D-26-15	STEEL SILO									
D-26-15-1	STEEL SILO	SOLID WASTE 35' DIA. SILO, SOLID WASTE HANDLING SYSTEM								
	D-26-15 Total									
	D-26 Total									
D-33	**MATERIAL HANDLING EQUIPMENT**									
D-33-13	ASH HANDLING EQUIPMENT									

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D-33-13-1	ASH HANDLING EQUIPMENT	PNEUMATIC SYSTEM INCLUDES: MECHANICAL EQUIPMENT INCLUDING NUVA FEEDERS, MECHANICAL BLOWER, FLUIDIZING SYSTEM AND BLOWERS, DUSTLESS UNLOADING, ISOLATION VALVES AND TRANSPORT AIR PIPING FROM FF TO FILTER SEPARATORS, BIN VENTS, ALL AIR & ASH TRANSPORT PIPING								
	D-33-13 Total									
	D-33 Total									
D-41	**ELECTRICAL EQUIPMENT**									
D-41-37	LIGHTING ACCESSORY (FIXTURE)									
D-41-37-1	LIGHTING ACCESSORY (FIXTURE)	BUILDING SERVICES, H&V AND LIGHTING, WASTE BLOWER BUILDING								
D-41-37-2	LIGHTING ACCESSORY (FIXTURE)	ELECTRICAL SERVICES AND LIGHTING, WASTE ASH SILO & STAIR TOWER								
	D-41-37 Total									
	D-41 Total									
	D Total									
E	**DUCTWORK FOR FLUE GAS SYSTEM**									
E-21	**CIVIL WORK**									
E-21-17	EARTHWORK, BACKFILL									
E-21-17-1	EARTHWORK, BACKFILL	DUCTWORK SUPPORT FOUNDATIONS, FLUE GAS SYSTEM								
	E-21-17 Total									
E-21-23	EARTHWORK, EXCAVATION									
E-21-23-1	EARTHWORK, EXCAVATION	DUCTWORK SUPPORT FOUNDATIONS, FLUE GAS SYSTEM								
E-21-23-2	EARTHWORK, EXCAVATION	VFD ENCLOSURE (30'X60'), FLUE GAS SYSTEM								
	E-21-23 Total									
	E-21 Total									
E-22	**CONCRETE**									
E-22-13	CONCRETE									
E-22-13-1	CONCRETE	DUCTWORK SUPPORT FOUNDATIONS, FLUE GAS SYSTEM								

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CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
	E-22-13 Total									
E-22-15	EMBEDMENT									
E-22-15-1	EMBEDMENT	DUCTWORK SUPPORT FOUNDATIONS, FLUE GAS SYSTEM								
	E-22-15 Total									
E-22-17	FORMWORK									
E-22-17-1	FORMWORK	DUCTWORK SUPPORT FOUNDATIONS, FLUE GAS SYSTEM								
	E-22-17 Total									
E-22-25	REINFORCING									
E-22-25-1	REINFORCING	DUCTWORK SUPPORT FOUNDATIONS, FLUE GAS SYSTEM								
	E-22-25 Total									
	E-22 Total									
E-23	**STEEL**									
E-23-15	DUCTWORK									
E-23-15-1	DUCTWORK	DUCTWORK STEEL, INCLUDING PLATE, STIFFENERS, INTERNAL BRACING, TURNING VANES AND WALKWAY GRATING, AIR HEATER OUTLET TO SPRAY DRY ABSORBER INLET DUCT								
E-23-15-2	DUCTWORK	INCLUDED WITH FGD EQUIPMENT COST								
E-23-15-3	DUCTWORK	DUCTWORK STEEL, INCLUDING PLATE, STIFFENERS, INTERNAL BRACING, TURNING VANES AND WALKWAY GRATING, FABRIC FILTER OUTLET DUCT TO ID FANS								
E-23-15-4	DUCTWORK	DUCTWORK STEEL, INCLUDING PLATE, STIFFENERS, INTERNAL BRACING, TURNING VANES AND WALKWAY GRATING, ID FAN OUTLET TO CHIMNEY BREECH								
	E-23-15 Total									
E-23-17	GALLERY									

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CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
E-23-17-1	GALLERY	ACCESS GALLERY FOR ALL INLET AND OUTLET DUCTWORK, FLUE GAS SYSTEM								
	E-23-17 Total									
E-23-25	ROLLED SHAPE - STRUCTURAL STEEL									
E-23-25-1	STRUCTURAL STEEL	DUCTWORK SUPPORT STEEL, FLUE GAS SYSTEM								
	E-23-25 Total									
	E-23 Total									
E-31	**MECHANICAL EQUIPMENT**									
E-31-27	DAMPERS & ACCESSORIES									
E-31-27-1	DAMPERS & ACCESSORIES	3 DAMPERS ON EACH SPRAY DRYER INLET (TOTAL OF 6), AIR HEATER OUTLET TO SPRAY DRY ABSORBER INLET DUCT (8'X14', SINGLE LOUVER)								
E-31-27-2	DAMPERS & ACCESSORIES	SINGLE LOUVER DAMPERS FOR SDA ISOLATION (27'X10'), AIR HEATER OUTLET TO SPRAY DRY ABSORBER INLET DUCT								
E-31-27-3	DAMPERS & ACCESSORIES	DAMPERS, SPRAY DRYER ABSORBER OUTLET TO FABRIC FILTER INLET - NOT REQUIRED								
E-31-27-4	DAMPERS & ACCESSORIES	FABRIC FILTER OUTLET DUCT TO ID FANS - INCLUDED WITH ID FAN REPLACEMENT								
E-31-27-5	DAMPERS & ACCESSORIES	ID FAN OUTLET TO CHIMNEY BREECH, INCLUDED WITH ID FAN REPLACEMENT								
E-31-27-6	DAMPERS & ACCESSORIES	ID FAN ISOLATION DAMPERS, SINGLE LOUVER TYPE DAMPER ASSEMBLY (18'X18'), ID FANS REPLACEMENT								
	E-31-27 Total									
E-31-33	EXPANSION JOINT									
E-31-33-1	EXPANSION JOINT	AIR HEATER OUTLET TO SPRAY DRY ABSORBER INLET DUCT								
E-31-33-2	EXPANSION JOINT	SPRAY DRYER ABSORBER OUTLET TO FABRIC FILTER INLET								
E-31-33-3	EXPANSION JOINT	FABRIC FILTER OUTLET DUCT TO ID FANS								

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E-31-33-4	EXPANSION JOINT	ID FAN OUTLET TO CHIMNEY BREECH								
	E-31-33 Total									
	E-31 Total									
E-36	**INSULATION**									
E-36-13	INSULATION, DUCT & EQUIPMENT									
E-36-13-1	INSULATION, DUCT & EQUIPMENT	INSULATION AND LAGGING, AIR HEATER OUTLET TO SPRAY DRY ABSORBER INLET DUCT								
E-36-13-2	INSULATION, DUCT & EQUIPMENT	INSULATION AND LAGGING, SPRAY DRYER ABSORBER OUTLET TO FABRIC FILTER INLET								
E-36-13-3	INSULATION, DUCT & EQUIPMENT	INSULATION AND LAGGING, FABRIC FILTER OUTLET DUCT TO ID FANS								
E-36-13-4	INSULATION, DUCT & EQUIPMENT	INSULATION AND LAGGING, ID FAN OUTLET TO CHIMNEY BREECH								
	E-36-13 Total									
	E-36 Total									
E-41	**ELECTRICAL EQUIPMENT**									
E-41-37	LIGHTING ACCESSORY (FIXTURE)									
E-41-37-1	LIGHTING ACCESSORY (FIXTURE)	LIGHTING FOR ACCESS GALLERIES AND ID FAN AREA								
	E-41-37 Total									
	E-41 Total									
E-44	**CONTROL & INSTRUMENTATION**									
E-44-21	INSTRUMENT									
E-44-21-1	INSTRUMENT	DRY FGD INLET DUCTWORK INSTRUMENTATION, AIR HEATER OUTLET TO SPRAY DRY ABSORBER INLET DUCT								
E-44-21-2	INSTRUMENT	DRY FGD OUTLET DUCTWORK INSTRUMENTATION, SPRAY DRYER ABSORBER OUTLET TO FABRIC FILTER INLET - INCLUDED IN DFGD PRICE								
E-44-21-3	INSTRUMENT	FABRIC FILTER OUTLET DUCTWORK INSTRUMENTATION, FABRIC FILTER OUTLET DUCT TO ID FANS								

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E-44-21-4	INSTRUMENT	ID FAN OUTLET DUCTWORK INSTRUMENTATION, ID FAN OUTLET TO CHIMNEY BREECH								
	E-44-21 Total									
	E-44 Total									
	E Total									
F	**ID FANS**									
F-21	**CIVIL WORK**									
F-21-17	EARTHWORK, BACKFILL									
F-21-17-1	EARTHWORK, BACKFILL	VFD ENCLOSURE (30'X60'), FLUE GAS SYSTEM								
F-21-17-2	EARTHWORK, BACKFILL	ID FAN FOUNDATIONS, FLUE GAS SYSTEM								
	F-21-17 Total									
F-21-23	EARTHWORK, EXCAVATION									
F-21-23-1	EARTHWORK, EXCAVATION	VFD ENCLOSURE (30'X60'), FLUE GAS SYSTEM								
F-21-23-2	EARTHWORK, EXCAVATION	ID FAN FOUNDATIONS, FLUE GAS SYSTEM								
	F-21-23 Total									
	F-21 Total									
F-22	**CONCRETE**									
F-22-13	CONCRETE									
F-22-13-1	CONCRETE	VFD ENCLOSURE (30'X60'), FLUE GAS SYSTEM								
F-22-13-2	CONCRETE	ID FAN FOUNDATIONS, FLUE GAS SYSTEM								
	F-22-13 Total									
F-22-15	EMBEDMENT									
F-22-15-1	EMBEDMENT	VFD ENCLOSURE (30'X60'), FLUE GAS SYSTEM								
F-22-15-2	EMBEDMENT	ID FAN FOUNDATIONS, FLUE GAS SYSTEM								
	F-22-15 Total									
F-22-17	FORMWORK									
F-22-17-1	FORMWORK	VFD ENCLOSURE (30'X60'), FLUE GAS SYSTEM								
F-22-17-2	FORMWORK	ID FAN FOUNDATIONS, FLUE GAS SYSTEM								
	F-22-17 Total									
F-22-25	REINFORCING									

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F-22-25-1	REINFORCING	VFD ENCLOSURE (30'X60'), FLUE GAS SYSTEM								
F-22-25-2	REINFORCING	ID FAN FOUNDATIONS, FLUE GAS SYSTEM								
	F-22-25 Total									
	F-22 Total									
F-31	**MECHANICAL EQUIPMENT**									
F-31-25	CRANES & HOISTS									
F-31-25-1	CRANES & HOISTS	HOIST & TROLLEYS FOR ID FANS (10 - TON CAP), ID FANS REPLACEMENT								
	F-31-25 Total									
F-31-27	DAMPERS & ACCESSORIES									
F-31-27-1	DAMPERS & ACCESSORIES	ID FAN ISOLATION DAMPERS, SINGLE LOUVER TYPE DAMPER ASSEMBLY (18'X18'), ID FANS REPLACEMENT								
	F-31-27 Total									
F-31-35	FANS & ACCESSORIES									
F-31-35-1	FANS & ACCESSORIES	NEW ID FANS, CENTRIFUGAL FANS, 2 x 50%, 1,200,000 CFM EACH, INCLUDES FAN AUXILIARY EQUIPMENT								
F-31-35-2	VARIABLE FREQUENCY DRIVE	15000 HP MOTOR AND VFD INSTALLATION - INCLUDES MOTORS, VFD's, VFD ENCLOSURE (30'X60'), HEAT EXCHANGERS, TECHNICAL FIELD ASSISTANCE, TRAINING								
F-31-35-3	MOTOR	INCLUDED WITH THE VFD								
	F-31-35 Total									
	F-31 Total									
F-36	**INSULATION**									
F-36-13	INSULATION, DUCT & EQUIPMENT									
F-36-13-1	INSULATION, DUCT & EQUIPMENT	FAN INSULATION AND LAGGING, ID FANS REPLACEMENT								
	F-36-13 Total									
	F-36 Total									
	F Total									
G	**MECHANICAL - BALANCE OF PLANT**									
G-21	**CIVIL WORK**									
G-21-17	EARTHWORK, BACKFILL									

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

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[TRADE SECRET DATA BEGINS

OTTER TAIL
BIG STONE STATION
DFGD
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
G-21-17-1	EARTHWORK, BACKFILL	BEDDING FOR UNDERGROUND PIPING, MAKEUP WATER								
G-21-17-2	EARTHWORK, BACKFILL	BACKFILL FOR UNDERGROUND PIPING, MAKEUP WATER								
G-21-17-3	EARTHWORK, BACKFILL	BEDDING FOR UNDERGROUND PIPING, SERVICE WATER								
G-21-17-4	EARTHWORK, BACKFILL	BACKFILL FOR UNDERGROUND PIPING, SERVICE WATER								
G-21-17-5	EARTHWORK, BACKFILL	BEDDING FOR UNDERGROUND PIPING, SUMP DISCHARGE / DRAINS								
G-21-17-6	EARTHWORK, BACKFILL	BACKFILL FOR UNDERGROUND PIPING, SUMP DISCHARGE / DRAINS								
G-21-17-7	EARTHWORK, BACKFILL	BEDDING FOR UNDERGROUND PIPING, FIRE PROTECTION								
G-21-17-8	EARTHWORK, BACKFILL	BACKFILL FOR UNDERGROUND PIPING, FIRE PROTECTION								
G-21-17-9	EARTHWORK, BACKFILL	PIPE AND CABLE TRAY RACK								
G-21-17-10	EARTHWORK, BACKFILL	MAKEUP WATER TANK 40' DIA.								
G-21-17-11	EARTHWORK, BACKFILL	SLURRY MAKEUP WATER TANK 22' DIA.								
	G-21-17 Total									
G-21-23	EARTHWORK, EXCAVATION									
G-21-23-1	EARTHWORK, EXCAVATION	EXCAVATION FOR UNDERGROUND PIPING, MAKEUP WATER								
G-21-23-2	EARTHWORK, EXCAVATION	EXCAVATION FOR UNDERGROUND PIPING, SERVICE WATER								
G-21-23-3	EARTHWORK, EXCAVATION	EXCAVATION FOR UNDERGROUND PIPING, SUMP DISCHARGE/DRAINS								
G-21-23-4	EARTHWORK, EXCAVATION	EXCAVATION FOR UNDERGROUND PIPING, FIRE PROTECTION								
G-21-23-5	EARTHWORK, EXCAVATION	PIPE AND CABLE TRAY RACK								
G-21-23-6	EARTHWORK, EXCAVATION	MAKEUP WATER TANK 40' DIA.								

TRADE SECRET DATA ENDS]

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G-21-23-7	EARTHWORK, EXCAVATION	SLURRY MAKEUP WATER TANK 22' DIA.								
	G-21-23 Total									
	G-21 Total									
G-22	**CONCRETE**									
G-22-13	CONCRETE									
G-22-13-1	CONCRETE	PIPE AND CABLE TRAY RACK								
G-22-13-2	CONCRETE	RING FOUNDATION, MAKEUP WATER TANK 40' DIA.								
G-22-13-3	CONCRETE	MAT FOUNDATION, SLURRY MAKEUP WATER TANK 22' DIA.								
	G-22-13 Total									
G-22-15	EMBEDMENT									
G-22-15-1	EMBEDMENT	PIPE AND CABLE TRAY RACK								
G-22-15-2	EMBEDMENT	MAKEUP WATER TANK 40' DIA.								
G-22-15-3	EMBEDMENT	SLURRY MAKEUP WATER TANK 22' DIA.								
	G-22-15 Total									
G-22-17	FORMWORK									
G-22-17-1	FORMWORK	PIPE AND CABLE TRAY RACK								
G-22-17-2	FORMWORK	MAKEUP WATER TANK 40' DIA.								
G-22-17-3	FORMWORK	SLURRY MAKEUP WATER TANK 22' DIA.								
	G-22-17 Total									
G-22-25	REINFORCING									
G-22-25-1	REINFORCING	PIPE AND CABLE TRAY RACK								
G-22-25-2	REINFORCING	MAKEUP WATER TANK 40' DIA.								
G-22-25-3	REINFORCING	SLURRY MAKEUP WATER TANK 22' DIA.								
	G-22-25 Total									
	G-22 Total									
G-23	**STEEL**									
G-23-25	ROLLED SHAPE - STRUCTURAL STEEL									
G-23-25-1	ROLLED SHAPE - STRUCTURAL STEEL	PIPE AND CABLE TRAY RACK								
	G-23-25 Total									
	G-23 Total									
G-31	**MECHANICAL EQUIPMENT**									
G-31-17	COMPRESSOR & ACCESSORIES									

TRADE SECRET DATA ENDS]

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G-31-17-1	COMPRESSOR & ACCESSORIES	AIR RECEIVERS, 1000 GAL								
G-31-17-2	COMPRESSOR & ACCESSORIES	AIR DRYERS, 250 NET SCFM, 100 psig								
	G-31-17 Total									
G-31-41	FIRE PROTECTION EQUIPMENT & SYSTEM									
G-31-41-1	FIRE PROTECTION EQUIPMENT	FIRE PROTECTION, STANDPIPE & HOSE STATION, WASTE BLOWER BUILDING								
G-31-41-2	FIRE PROTECTION EQUIPMENT	HYDRANTS								
	G-31-41 Total									
G-31-65	HEAT EXCHANGER									
G-31-65-1	HEAT EXCHANGER	SLURRY WATER TANK STEAM HEATERS,								
	G-31-65 Total									
G-31-75	PUMPS									
G-31-75-1	PUMPS	MAKEUP WATER PUMPS, 1000 GPM, 200FT TDH								
G-31-75-2	PUMPS	SLURRY WATER MAKEUP WATER PUMPS, 400 GPM, 200FT TDH								
G-31-75-3	PUMPS	SUMP PUMPS, 440GPM , 220 TDH								
G-31-75-4	PUMPS	SLAKER MU PUMPS 10HP, 100GPMX150FT, DEMIN AREA								
	G-31-75 Total									
G-31-83	TANKS									
G-31-83-1	TANKS	MAKEUP WATER TANK 40' DIA. X 45', 1 - 12 HOUR TANK. SUBCONTRACT COST INCLUDES MATERIAL AND LABOR								
G-31-83-2	TANKS	SLURRY MAKEUP WATER TANK 22' DIA. X 25', 1 - 12 HOUR TANK. SUBCONTRACT COST INCLUDES MATERIAL AND LABOR								
	G-31-83 Total									
	G-31 Total									
G-35	**PIPING**									
G-35-13										
G-35-13-1	LARGE BORE	VACUUM CONVEYING TO LIME SILO, VACUUM CONVEYING - INCLUDED IN LIME SILO COST								

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PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

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G-35-13-2	LARGE BORE	6" HDPE SDR11, INCLUDES FITTINGS, UNDERGROUND, HOLDING POND TO RECYCLE MU TANK; MAKE UP WATER								
G-35-13-3	LARGE BORE	4" HDPE SDR11, INCLUDES FITTINGS, UNDERGROUND, POET RO REJECT TO RECYCLE MU TANK; MAKE UP WATER								
G-35-13-4	LARGE BORE	6" SS, SCH 40S, INCLUDES FITTINGS, SUPPORTED ON PIPE RACK, RO PERMEATE TO BC PRETREATMENT/DEMIN; MAKEUP WATER								
G-35-13-5	LARGE BORE	3" CS, SCH 40, INCLUDES FITTINGS, TURBINE BUILDING SLAKER; MAKEUP WATER								
G-35-13-6	LARGE BORE	PIPE SUPPORTS FOR 3" CS PIPING, TURBINE BUILDING SLAKER; MAKEUP WATER								
G-35-13-7	LARGE BORE	3" HDPE SDR11, INCLUDES FITTINGS, UNDERGROUND, SLAKER WATER-TURBINE BUILDING TO MU TANK; MAKEUP WATER								
G-35-13-8	LARGE BORE	6" CS, SCH 40, INCLUDES FITTINGS, UPGRADE EXISTING BS BOILER ROOM HP SERVICE WATER TO WASTE SILO, SERVICE WATER								
G-35-13-9	LARGE BORE	PIPE SUPPORTS FOR SERVICE WATER PIPING								
G-35-13-10	LARGE BORE	6" HDPE SDR11, INCLUDES FITTINGS, UNDERGROUND, UPGRADE EXISTING OUTDOOR HP SERVICE WATER TO WASTE SILO, SERVICE WATER								
G-35-13-11	LARGE BORE	3" HDPE SDR11, INCLUDES FITTINGS, UNDERGROUND, BRANCH PIPING TO SDA, RECYCLE AND LIME PREP BUILDING, SERVICE WATER								
G-35-13-12	LARGE BORE	3" CS, SCH 40, INCLUDES FITTINGS, BRANCH PIPING TO SDA, RECYCLE AND LIME PREP BUILDINGS, SERVICE WATER								

TRADE SECRET DATA ENDS]

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G-35-13-13	LARGE BORE	PIPE SUPPORTS FOR SERVICE WATER PIPING								
G-35-13-14	LARGE BORE	3" CS, SCH 80, INCLUDES FITTINGS, SUPPORT ON PIPE RACK AND BUILDING STEEL, PIPING FROM SDA TO SLURRY TANK; LIME SLURRY SUPPLY PIPE								
G-35-13-15	LARGE BORE	PIPE SUPPORTS, SDA AND LIME PREP BUILDING; LIME SLURRY SUPPLY PIPE								
G-35-13-16	LARGE BORE	FLUSH WATER PIPING, LIME SLURRY SUPPLY PIPE - INCLUDED IN LINE H-35-13-17								
G-35-13-17	LARGE BORE	2.5" CS, SCH 80, INCLUDES FITTINGS, SUPPORTED ON PIPE RACK AND BUILDING STEEL, PIPING FROM SDA TO SLURRY TANK, LIME SLURRY RETURN PIPE								
G-35-13-18	LARGE BORE	PIPE SUPPORTS, SDA AND LIME PREP BUILDINGS, LIME SLURRY RETURN PIPE								
G-35-13-19	LARGE BORE	FLUSH WATER PIPING, LIME SLURRY RETURN PIPE - INCLUDED IN LINE H-35-13-17								
G-35-13-20	LARGE BORE	8" CS, SCH 80, INCLUDES FITTINGS, SUPPORT ON PIPE RACK AND BUILDING STEEL, RECYCLE ASH SILO TO ATOMIZER HEAD TANK; RECYCLE SLURRY PIPE								
G-35-13-21	LARGE BORE	PIPE SUPPORTS, SDA AND LIME PREP BUILDING, RECYCLE SLURRY PIPE								
G-35-13-22	LARGE BORE	FLUSH WATER PIPING, RECYCLE SLURRY PIPE - INCLUDED IN LINE H-35-13-17								
G-35-13-23	LARGE BORE	4" CS, SCH 80, INCLUDES FITTINGS, SUPPORT ON BUILDING STEEL AND PIPE RACK, ATOMIZER HEAD TANK TO RECYCLE BUILDING, UNDERGROUND; RECYCLE SLURRY RETURN PIPE								
G-35-13-24	LARGE BORE	PIPE SUPPORTS, SDA AND LIME PREP BUILDING; RECYCLE SLURRY RETURN PIPE								

TRADE SECRET DATA ENDS]

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G-35-13-25	LARGE BORE	FLUSH WATER PIPING; RECYCLE SLURRY RETURN PIPE - INCLUDED IN LINE H-35-13-17								
G-35-13-26	LARGE BORE	10" ASHCOLITE, FLANGED, SUPPORTS INCLUDED WITH PIPE RACK FROM BH TO WASTE SILO; SOLID WASTE PIPE - INCLUDED WITH UCC BUDGET ESTIMATE								
G-35-13-27	LARGE BORE	PIPE SUPPORTS, BENEATH BH AND IN RECYCLE BUILDING; SOLID WASTE PIPE								
G-35-13-28	LARGE BORE	4" CS, SCH 40, INCLUDES FITTINGS, SUPPORTED ON PIPE RACK, HEADER TO SCR AND SDA; SERVICE AIR								
G-35-13-29	LARGE BORE	3" CS, SCH 40, INCLUDES FITTINGS, SUPPORTED ON PIPE RACK, HEADER TO REACTANT PREP AND RECYCLE; SERVICE AIR								
G-35-13-30	LARGE BORE	3" 304SS, SCH 40S, WELDED, SUPPORTED ON PIPE RACK, HEADER TO SCR AND SDA, INSTRUMENT AIR								
G-35-13-31	LARGE BORE	PIPE SUPPORTS FOR INSTRUMENT AIR								
G-35-13-32	LARGE BORE	4" CS, SCH 40, INCLUDES FITTINGS, SDA, LIME PREP & RECYCLE BUILDING; SUMP DISCHARGE/DRAINS								
G-35-13-33	LARGE BORE	PIPE SUPPORTS FOR SUMP DISCHARGE AND DRAINS								
G-35-13-34	LARGE BORE	4" HDPE SDR11 INCLUDES FITTINGS, SDA AREA TO MAIN HEADER; SUMP DISCHARGE/DRAINS								
G-35-13-35	LARGE BORE	6" HDPE SDR11 INCLUDES FITTINGS, MAIN HEADER TO BASIN AND BASIN TO RECYCLE MU TANK; SUMP DISCHARGE/DRAINS								
G-35-13-36	LARGE BORE	STEAM HEADER TO FGD AREA 4" SCH 40 ,								
G-35-13-37	LARGE BORE	SUPPORTS - STEAM HEADER TO FGD AREA 4" SCH 40 ,								
G-35-13-38	LARGE BORE	STEAM HEADER TO FGD AREA 3" SCH 40 ON RACK								

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G-35-13-39	LARGE BORE	6" CI VALVES WITH PIVS								
G-35-13-40	LARGE BORE	4" CS GATE CLASS 150								
G-35-13-41	LARGE BORE	3" CS GATE CLASS 150								
G-35-13-42	LARGE BORE	6" SS GATE CLASS 150								
G-35-13-43	LARGE BORE	8" CS GATE CLASS 150								
G-35-13-44	LARGE BORE	4" CS CONTROL VALVE-PNEUMATIC								
G-35-13-45	LARGE BORE	4" CS CONTROL VALVE- 600 LB PNEUMATIC STEAM SUPPLY TO HEATING UNITS								
G-35-13-46	LARGE BORE	3" CS CONTROL VALVE-PNEUMATIC								
G-35-13-47	LARGE BORE	8" HDPE, SDR11, TIE IN TO EXISTING 6" KHJ-101 U/G, EXCESS CLS EFFLUENT TO MU POND								
G-35-13-48	LARGE BORE	4" HDPE, SDR11, U/G, UF BACKWASH TO CLS								
G-35-13-49	LARGE BORE	6" CS, SCH 40, INCLUDES FITTINGS, A/G , ID FAN L.O. RETURN								
G-35-13-50	LARGE BORE	8" CS, SCH 40, BASALT LINED INCLUDES FITTINGS, ASH SLUICE PIPE EACH HOPPER - PROCESS AREA								
G-35-13-51	LARGE BORE	8" CS, SCH 40, INCLUDES FITTINGS, SLUICE WATER PIPE EACH HOPPER - PROCESS AREA								
G-35-13-52	LARGE BORE PIPE SUPPORTS									
	G-35-13 Total									
G-35-15										
G-35-15-1	SMALL BORE	2" CS, SCH 80, INCLUDES FITTINGS, SCR, BH, SDA LIME RECYCLE, SERVICE AIR								
G-35-15-2	SMALL BORE	2" CS, SCH 80, INCLUDES FITTINGS, BRANCH PIPING TO SDA, RECYCLE AND LIME PREP BUILDINGS, SERVICE WATER								
G-35-15-3	SMALL BORE	STEAM HEADER TO UNIT HEATERS, 2"' CS SCH 80								
G-35-15-4	SMALL BORE	STEAM TO UNIT HEATERS, 1.5"' CS SCH 60								
G-35-15-5	SMALL BORE	CONDENSATE DRAINS UNIT HEATERS, 1.5"' CS SCH 60								

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G-35-15-6	SMALL BORE	2" 304SS, SCH 40S, WELDED, SUPPORTED ON PIPE RACK, HEADER TO REACTANT PREP AND RECYCLE, INSTRUMENT AIR								
G-35-15-7	SMALL BORE	1" 304SS, SCH 40S, WELDED, SCR, BH, SDA LIME AND RECYCLE, INSTRUMENT AIR								
G-35-15-8	SMALL BORE	1" AND <, 316SS, 0.049" TUBING, COMPRESSION JOINTS, SCR, BH, SDA LIME AND RECYCLE								
G-35-15-9	SMALL BORE	1" BRONZE BALL								
G-35-15-10	SMALL BORE	2" BRONZE, BALL								
G-35-15-11	SMALL BORE	SMALL BORE VALVES, CS WELDED								
G-35-15-12	SMALL BORE	2" CS CONTROL VALVE-PNEUMATIC								
G-35-15-13	SMALL BORE	2" SS CONTROL VALVE-PNEUMATIC								
G-35-15-14	SMALL BORE	1.5" CS, SCH 80, INCLUDES FITTINGS, A/G SUPPORTED ON PIPE RACK, LIME SLURRY EXTENSION TO CLS								
G-35-15-15	SMALL BORE	2" GA CS, SCH 40, INCLUDES FITTINGS, U/G , DOMESTIC WATER								
G-35-15-16	SMALL BORE	1.5" GA CS, SCH 40, INCLUDES FITTINGS, A/G , DOMESTIC WATER								
G-35-15-17	SMALL BORE	2" SS, SCH 80, INCLUDES FITTINGS, A/G , ID FAN L.O. SUPPLY								
G-35-15-18	SMALL BORE PIPE SUPPORTS									
	G-35-15 Total									
	G-35 Total									
G-36	**INSULATION**									
G-36-13	INSULATION, DUCT & EQUIPMENT									
G-36-13-1	INSULATION, SLURRY WATER TANK	SLURRY WATER TANK								
	G-36-13 Total									
G-36-15	INSULATION, PIPE									
G-36-15-1	INSULATION, PIPE	INSULATION FOR HEAT TRACED PIPING, ASSUMED NOMINAL 4" PIPE SIZE								

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G-36-15-2	INSULATION, PIPE	2" MINERAL WOOL W AL JACKET INSULATION FOR STEAM PIPING, ASSUMED NOMINAL 4" PIPE SIZE								
	G-36-15 Total									
	G-36 Total									
G-41	**ELECTRICAL EQUIPMENT**									
G-41-33	HEAT TRACING									
G-41-33-1	HEAT TRACING	HEAT TRACING CABLE								
G-41-33-2	HEAT TRACING	POWER CONNECTOR AND OTHER ACCESSORIES INCLUDING THERMOSTATS FOR HEAT TRACING (BY ZONES)								
	G-41-33 Total									
	G-41 Total									
	G Total									
H	**ELECTRICAL - AUXILIARY POWER AND BALANCE OF PLANT ELECTRICAL WORK**									
H-11	**DEMOLITION WORK**									
H-11-41	ELECTRICAL EQUIPMENT									
H-11-41-1	ELECTRICAL EQUIPMENT	DISCONNECT & REMOVE EXISTING 800A & 1200A MCCS FROM BAG HOUSE, DISMANTLE & HAUL AWAY; AUXILIARY POWER MODIFICATIONS								
H-11-41-2	ELECTRICAL EQUIPMENT	DISCONNECT & REMOVE EXISTING 3200A, 480V SWGR FROM BAG HOUSE, DISMANTLE & HAUL AWAY; AUXILIARY POWER MODIFICATIONS								
	H-11-41 Total									
	H-11 Total									
H-21	**CIVIL WORK**									
H-21-17	EARTHWORK, BACKFILL									
H-21-17-1	EARTHWORK, BACKFILL	FOUNDATIONS FOR AQCS MAIN EEB								
H-21-17-2	EARTHWORK, BACKFILL	RECYCLE ASH & SLURRY PREP AREA EEB								
H-21-17-3	EARTHWORK, BACKFILL	TRANSFORMER FOUNDATIONS, RAT								
H-21-17-4	EARTHWORK, BACKFILL	TRANSFORMER FOUNDATIONS, UAT								

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H-21-17-5	EARTHWORK, BACKFILL	CABLE BUS SUPPORT								
	H-21-17 Total									
H-21-23	EARTHWORK, EXCAVATION									
H-21-23-1	EARTHWORK, EXCAVATION	FOUNDATIONS FOR AQCS MAIN EEB								
H-21-23-2	EARTHWORK, EXCAVATION	RECYCLE ASH & SLURRY PREP AREA EEB								
H-21-23-3	EARTHWORK, EXCAVATION	TRANSFORMER FOUNDATIONS, RAT								
H-21-23-4	EARTHWORK, EXCAVATION	TRANSFORMER FOUNDATIONS, UAT								
H-21-23-5	EARTHWORK, EXCAVATION	CABLE BUS SUPPORT								
	H-21-23 Total									
	H-21 Total									
H-22	**CONCRETE**									
H-22-13	CONCRETE									
H-22-13-1	CONCRETE	FOUNDATIONS FOR AQCS MAIN EEB								
H-22-13-2	CONCRETE	RECYCLE ASH & SLURRY PREP AREA EEB								
H-22-13-3	CONCRETE	TRANSFORMER FOUNDATIONS INCLUDING FIRE WALLS, RAT								
H-22-13-4	CONCRETE	TRANSFORMER FOUNDATIONS INCLUDING FIRE WALLS, UAT								
H-22-13-5	CONCRETE	CABLE BUS SUPPORT								
	H-22-13 Total									
H-22-15	EMBEDMENT									
H-22-15-1	EMBEDMENT	FOUNDATIONS FOR AQCS MAIN EEB								
H-22-15-2	EMBEDMENT	RECYCLE ASH & SLURRY PREP AREA EEB								
H-22-15-3	EMBEDMENT	TRANSFORMER FOUNDATIONS, RAT								
H-22-15-4	EMBEDMENT	TRANSFORMER FOUNDATIONS, UAT								
H-22-15-5	EMBEDMENT	CABLE BUS SUPPORT								
	H-22-15 Total									
H-22-17	FORMWORK									
H-22-17-1	FORMWORK	FOUNDATIONS FOR AQCS MAIN EEB								

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PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

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H-22-17-2	FORMWORK	RECYCLE ASH & SLURRY PREP AREA EEB								
H-22-17-3	FORMWORK	TRANSFORMER FOUNDATIONS, RAT								
H-22-17-4	FORMWORK	TRANSFORMER FOUNDATIONS, UAT								
H-22-17-5	FORMWORK	CABLE BUS SUPPORT								
	H-22-17 Total									
H-22-25	REINFORCING									
H-22-25-1	REINFORCING	FOUNDATIONS FOR AQCS MAIN EEB								
H-22-25-2	REINFORCING	RECYCLE ASH & SLURRY PREP AREA EEB								
H-22-25-3	REINFORCING	TRANSFORMER FOUNDATIONS, RAT								
H-22-25-4	REINFORCING	TRANSFORMER FOUNDATIONS, UAT								
H-22-25-5	REINFORCING	CABLE BUS SUPPORT								
	H-22-25 Total									
	H-22 Total									
H-23	**STEEL**									
H-23-17	GALLERY									
H-23-17-1	GALLERY	1-1/4" GRATING (GALV), BASIN GRATING								
	H-23-17 Total									
H-23-25	STRUCTURAL STEEL									
H-23-25-1	STRUCTURAL STEEL	BASIN GALLERY STEEL FOR CONTAINMENTS								
H-23-25-2	STRUCTURAL STEEL	CABLE BUS SUPPORT								
	H-23-25 Total									
	H-23 Total									
H-24	**ARCHITECTURAL**									
H-24-35	PRE-ENGINEERED BUILDING									
H-24-35-1	PRE-ENGINEERED BUILDING	AQCS - ELECTRICAL EQUIPMENT BUILDING # 11- (MCC & SWGR COST INCLUDED SEPARATELY), (15'X60') BUILDING, INCLUDES: ENCLOSURE WITH HVAC AND LIGHTING/ELECTRIC SERVICE UPS, BATTERIES / CHARGERS ROOM/AREA DESIGNATED FOR DCS PHONE JACK, AUXILIARY POWER MODIFICATI								

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H-24-35-2	PRE-ENGINEERED BUILDING	RECYCLE AND ASH SLURRY PREP - ELECTRICAL EQUIPMENT BUILDING # 12 (PREP & RECYCLE AREA)- (MCC & SWGR COST INCLUDED SEPARATELY), (15'X60') BUILDING, INCLUDES: ENCLOSURE (270K) WITH HVAC AND LIGHTING/ELECTRIC SERVICE; UPS, BATTERIES / CHARGERS ROOM/AREA DESI								
H-24-35-3	PRE-ENGINEERED BUILDING	BAGHOUSE - ELECTRICAL EQUIPMENT BUILDING # 15 (BAG HOUSE)-(MCC & SWGR COST INCLUDED SEPARATELY), (15'X45') BUILDING, INCLUDES: ENCLOSURE WITH HVAC AND LIGHTING/ELECTRIC SERVICE; AUXILIARY POWER MODIFICATIONS. LOCATED ON FABRIC FILTER MAT SLAB								
	H-24-35 Total									
	H-24 Total									
H-35	**PIPING**									
H-35-35	PIPING									
H-35-35-1	PIPING	INSTRUMENT TUBING								
	H-35-35 Total									
	H-35 Total									
H-41	**ELECTRICAL EQUIPMENT**									
H-41-13	CABLE BUS DUCT									
H-41-13-1	CABLE BUS DUCT	15KV, 2000A, 3 PHASE CABLE BUS, (1000'+ 800')								
H-41-13-2	CABLE BUS DUCT	#750 KCM CABLE BUS TERMINATIONS								
	H-41-13 Total									
H-41-15	CATHODIC PROTECTION									
H-41-15-1	CATHODIC PROTECTION	CATHODIC PROTECTION, TO ELECTRICAL SYSTEM (ALLOWANCE)								
	H-41-15 Total									
H-41-17	COMMUNICATION SYSTEM									

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H-41-17-1	COMMUNICATION SYSTEM	PA / PAGE PARTY EXTENSION SYSTEM, LIME SILO & REAGENT PREP BUILDING, RECYCLE BUILDING, BAGHOUSE ENCLOSURE, WATER TREATMENT BUILDING, WASTE BLOWER BUILDING, ELECTRICAL EQUIPMENT BUILDINGS & WAREHOUSE								
H-41-17-2	COMMUNICATION SYSTEM	DATA COM EXTENSION SYSTEM - LIME SILO & REAGENT PREP BUILDING, RECYCLE BUILDING, BAGHOUSE ENCLOSURE, WATER TREATMENT BUILDING, WASTE BLOWER BUILDING, ELECTRICAL EQUIPMENT BUILDINGS & WAREHOUSE								
H-41-17-3	COMMUNICATION SYSTEM	TELEPHONE EXTENSION SYSTEM - LIME SILO & REAGENT PREP BUILDING, RECYCLE BUILDING, BAGHOUSE ENCLOSURE, WATER TREATMENT BUILDING, WASTE BLOWER BUILDING, ELECTRICAL EQUIPMENT BUILDINGS & WAREHOUSE								
	H-41-17 Total									
H-41-25	FIRE DETECTION, PROTECTION									
H-41-25-1	FIRE DETECTION	TIE IN & UPGRADE FIRE DETECTION SYSTEM TO EXISTING ALARM SYSTEM								
	H-41-25 Total									
H-41-31	GROUNDING									
H-41-31-1	GROUNDING	GROUNDING; INCLUDING GND ROD, BARE WIRE & TERMINATION / CAD WELD - FOR THE ENTIRE PROJECT AREA INCLUDING AMMONIA TANK FARM								
	H-41-31 Total									
H-41-35	LIGHTNING PROTECTION									
H-41-35-1	LIGHTNING PROTECTION	#500 KCMIL								
H-41-35-2	LIGHTNING PROTECTION	#4/0 BARE COPPER								
H-41-35-3	LIGHTNING PROTECTION	CAD WELD & WIRE TERMINATION								

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	H-41-35 Total									
H-41-45	MOTOR CONTROL CENTER (MCC)									
H-41-45-1	MOTOR CONTROL CENTER (MCC)	MCC-800A, 480V, 3 PHASE; AUXILIARY POWER MODIFICATIONS								
H-41-45-2	MOTOR CONTROL CENTER (MCC)	MCC-400A, 480V, 3 PHASE; AUXILIARY POWER MODIFICATIONS								
	H-41-45 Total									
H-41-47	PANEL: CONTROL, DISTRIBUTION, & RELAY									
H-41-47-1	PANEL: CONTROL, DISTRIBUTION, & RELAY	PROTECTIVE RELAY PANELS & MISC HDWR (ALLOWANCE)								
	H-41-47 Total									
H-41-51	POWER TRANSFORMER									
H-41-51-1	POWER TRANSFORMER	LIGHTING TRANSFORMERS 45KVA, 480V, 3 PHASE, LOW VOLTAGE XFMR; AUXILIARY POWER MODIFICATIONS								
H-41-51-2	POWER TRANSFORMER	UAT- TRANSFORMER-24kV - 13.8kV, 21/28/35 MVA, 3PHASE; AUXILIARY POWER MODIFICATIONS								
H-41-51-3	POWER TRANSFORMER	TRANSFORMER, 480 V FOR DOUBLE ENDED SUBSTATION, 13.8KV-480V,3phase, 2000/2666KVA; AUXILIARY POWER MODIFICATIONS								
	H-41-51 Total									
H-41-55	SWITCHGEAR									
H-41-55-1	SWITCHGEAR	2000A, 13.8KV SWITCHGEAR WITH 2-2000A BREAKERS & 4-1200A BREAKERS; AUXILIARY POWER MODIFICATIONS								
H-41-55-2	SWITCHGEAR	3200A, 480V SWITCHGEAR WITH - 3200A TIE BREAKER & 6-800A BREAKERS; AUXILIARY POWER MODIFICATIONS								
	H-41-55 Total									
H-41-53	SECURITY SYSTEM									
H-41-53-1	SECURITY SYSTEM	SECURITY SYSTEM; (SDA, FABRIC FILTER) ALLOWANCE								
	H-41-53 Total									
	H-41 Total									
H-42	**RACEWAY, CABLE TRAY, & CONDUIT**									
H-42-13	CABLE TRAY									

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H-42-13-1	CABLE TRAY	CABLE TRAY 36"; LIME SILO & REAGENT PREP BUILDING, RECYCLE BUILDING, BAGHOUSE ENCLOSURE, WATER TREATMENT BUILDING, WASTE BLOWER BUILDING & ELECTRICAL EQUIPMENT BUILDINGS								
H-42-13-2	CABLE TRAY	CABLE TRAY, 24" LIME SILO & REAGENT PREP BUILDING, RECYCLE BUILDING, BAGHOUSE ENCLOSURE, WATER TREATMENT BUILDING, WASTE BLOWER BUILDING & ELECTRICAL EQUIPMENT BUILDINGS								
	H-42-13 Total									
H-42-15	CONDUITS									
H-42-15-1	CONDUITS	MISC SIZES (4" to 6") ENTIRE PROJECT AREA INCLUDING AMMONIA TANK FARM								
H-42-15-2	CONDUITS	MISC SIZES (3/4" to 3") ENTIRE PROJECT AREA INCLUDING AMMONIA TANK FARM								
	H-42-15 Total									
H-42-17	CONDUIT BOX									
H-42-17-1	CONDUIT BOX	MISC. JUNCTION BOXES & PULL BOXES; ENTIRE PROJECT AREA INCLUDING AMMONIA TANK FARM								
	H-42-17 Total									
	H-42 Total									
H-43	**CABLE**									
H-43-13	CONTROL & INSTRUMENT CABLE									
H-43-13-1	CONTROL & INSTRUMENT CABLE	2/C #14;								
H-43-13-2	CONTROL & INSTRUMENT CABLE	3/C, #14;								
H-43-13-3	CONTROL & INSTRUMENT CABLE	5/C, #14;								
H-43-13-4	CONTROL & INSTRUMENT CABLE	7/C, #14;								
H-43-13-5	CONTROL & INSTRUMENT CABLE	9/C, #14;								
H-43-13-6	CONTROL & INSTRUMENT CABLE	2 PR, #16 TW SHLD;								
H-43-13-7	CONTROL & INSTRUMENT CABLE	FIBER OPTIC CABLE, 2 STRAND;								
H-43-13-8	CONTROL & INSTRUMENT CABLE	FIBER OPTIC CABLE, 6 STRAND;								

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H-43-13-9	CONTROL & INSTRUMENT CABLE	FIBER OPTIC CABLE, 12 STRAND;								
H-43-13-10	CONTROL & INSTRUMENT CABLE	FIBER OPTIC CABLE, 24 STRAND;								
H-43-13-11	CONTROL & INSTRUMENT CABLE	CAT 5E								
H-43-13-12	CONTROL & INSTRUMENT CABLE	1 PR, #16 TW SHLD								
H-43-13-13	CONTROL & INSTRUMENT CABLE	1PR #16 TW SHLD; 300 V								
H-43-13-14	CONTROL & INSTRUMENT CABLE	2 PR, #16 TW SHLD; 300 V								
H-43-13-15	CONTROL & INSTRUMENT CABLE	2/C #16 TW SHLD; 300 V								
H-43-13-16	CONTROL & INSTRUMENT CABLE	4/C #16 TW SHLD; 300 V								
H-43-13-17	CONTROL & INSTRUMENT CABLE	INSTRUMENTATION CABLE TERMINATIONS								
	H-43-13 Total									
H-43-17	LOW VOLTAGE POWER CABLE & TERMINATIONS									
H-43-17-1	LOW VOLTAGE POWER CABLE	1/C #750-600V POWER FEEDER CABLE TO MCC & 480V SWGR, 25000'+ 7500								
H-43-17-2	LOW VOLTAGE POWER CABLE	3/C# 350KCMIL, 600 V								
H-43-17-3	LOW VOLTAGE POWER CABLE	3/C, #4/0, 600 V								
H-43-17-4	LOW VOLTAGE POWER CABLE	3/C, #1/0, 600 V								
H-43-17-5	LOW VOLTAGE POWER CABLE	3/C, #2, 600 V								
H-43-17-6	LOW VOLTAGE POWER CABLE	3/C, #4 600 V								
H-43-17-7	LOW VOLTAGE POWER CABLE	3/C, #6 - 600 V								
H-43-17-8	LOW VOLTAGE POWER CABLE	3/C,#8 600 V								
H-43-17-9	LOW VOLTAGE POWER CABLE	3/C, #10, 600 V								
H-43-17-10	LOW VOLTAGE POWER CABLE	#750 KCM WIRE TERMINATIONS + WIRE TAG								
H-43-17-11	LOW VOLTAGE POWER CABLE	#350 KCM WIRE TERMINATIONS + WIRE TAG								
H-43-17-12	LOW VOLTAGE POWER CABLE TERMINATIONS	600V POWER & CONTROL CABLE TERMINATIONS								
	H-43-17 Total									
H-43-21	**MEDIUM VOLTAGE POWER CABLE & TERMINATION**									
H-43-21-1	MEDIUM VOLTAGE POWER CABLE	1/C # 500KCMIL, 15KV (12000' + 5000')								
H-43-21-2	MEDIUM VOLTAGE POWER CABLE	3/C # 250KCMIL, 15KV, (300'+ 1400' + 1600'+ 3200')								
H-43-21-3	MEDIUM VOLTAGE POWER CABLE	3/C, #4/0, 15KV								
H-43-21-4	MEDIUM VOLTAGE POWER CABLE TERMINATION	# 250 KCMIL, 15KV WIRE TERMINATIONS + WIRE TAG								
H-43-21-5	MEDIUM VOLTAGE POWER CABLE TERMINATION	# 500 KCMIL, 15KV WIRE TERMINATIONS + WIRE TAG								

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H-43-21-6	MEDIUM VOLTAGE POWER CABLE TERMINATION	# 4/0, 5KV WIRE TERMINATIONS + WIRE TAG								
	H-43-21 Total									
	H-43 Total									
H-44	**CONTROL & INSTRUMENTATION**									
H-44-13	CONTROL SYSTEM									
H-44-13-1	CONTROL SYSTEM	DCS, 2500 I/O POINTS								
H-44-13-2	VENDOR TECHNICAL ADVISORY SERVICE	DCS - VENDOR FIELD SUPPORT, 150 MANDAYS @ $1500/DAY								
	H-44-13 Total									
H-44-17	INSTRUMENT PANEL, RACK									
H-44-17-1	INSTRUMENT PANEL, RACK	INSTRUMENT RACKS								
	H-44-17 Total									
H-44-21	INSTRUMENT									
H-44-21-1	INSTRUMENT	LOCALLY MOUNTED INSTRUMENTS NOT INCLUDED WITH DFGD EQUIPMENT								
	H-44-21 Total									
	H-44 Total									
H-51	**SUBSTATION, SWITCHYARD & TRANSMISSION LINE**									
H-51-15	ELECTRICAL EQUIPMENT									
H-51-15-1	ELECTRICAL EQUIPMENT (POWER TRANSFORMER)	RAT/SST TRANSFORMER, 230kV - 13.8kV, 21/28/35 MVA, 3phase; AUXILIARY POWER MODIFICATIONS								
	H-51-15 Total									
H-51-21	SUBSTATION, SWITCHYARD & TRANSMISSION LINE									
H-51-21-1	SUBSTATION, SWITCHYARD & TRANSMISSION LINE	230KV, 3PHASE BREAKER-2000A CB; 900kV BIL, 50 kA, GAS FILLED (SF6) - INCLUDES SUPPORTS. AUXILIARY POWER MODIFICATIONS								
H-51-21-2	SUBSTATION, SWITCHYARD & TRANSMISSION LINE	BASE FOR 230KV BREAKER, WITH (11'L X 9'W X 1'H) CONCRETE PAD AND STRUCTURE; AUXILIARY POWER MODIFICATIONS								
H-51-21-3	SUBSTATION, SWITCHYARD & TRANSMISSION LINE	230KV , 3PHASE DISCONNECT SWITCH; 2000A - AUXILIARY POWER MODIFICATIONS								

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H-51-21-4	SUBSTATION, SWITCHYARD & TRANSMISSION LINE	BASE FOR 230KV DISCONNECT SWITCH, WITH 2(3'W X17'L) SECTION & STRUCTURE SUPPORT; AUXILIARY POWER MODIFICATIONS								
H-51-21-5	SUBSTATION, SWITCHYARD & TRANSMISSION LINE	230KV DEAD-END STRUCTURE, WITH 4 CESSIONS & STRUCTURE SUPPORT; AUXILIARY POWER MODIFICATIONS								
H-51-21-6	SUBSTATION, SWITCHYARD & TRANSMISSION LINE	90' POLE FOR 230KV OVERHEAD LINE + CROSS SUPPORT & MISC. HDWR, WITH 3'W X 10'L SECTION - AUXILIARY POWER MODIFICATIONS								
H-51-21-7	SUBSTATION, SWITCHYARD & TRANSMISSION LINE	230KV OVERHEAD LINE CONDUCTORS, 795KCM (1000'x 3); AUXILIARY POWER MODIFICATIONS								
H-51-21-8	SUBSTATION, SWITCHYARD & TRANSMISSION LINE	230KV INSULATOR F& MISC HDWR FOR OVERHEAD LINE CONDUCTORS; AUXILIARY POWER MODIFICATIONS								
H-51-21-9	ELECTRICAL EQUIPMENT	230KV DEAD-END STRUCTURE, WITH 4 SECTIONS & STRUCTURE SUPPORT; AUXILIARY POWER MODIFICATIONS								
H-51-21-10	ELECTRICAL EQUIPMENT	3-SINGLE PHASE CCVT'S								
H-51-21-11	ELECTRICAL EQUIPMENT	ALLOWANCE FOR SUPPORT STRUCTURES AND FOUNDATION FOR CCVT'S								
	H-51-21 Total									
	H-51 Total									
H-71	**PROJECT INDIRECTS**									
H-71-55	VENDOR TECHNICAL ADVISORY SERVICE									
H-71-55-1	VENDOR TECHNICAL ADVISORY SERVICE	INCLUDED WITH EQUIPMENT COSTS								
	H-71-55 Total									
	H-71 Total									
	H Total									
I	**MISCELLANEOUS BUILDINGS**									
I-21	**CIVIL WORK**									
I-21-17	EARTHWORK, BACKFILL									

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I-21-17-1	EARTHWORK, BACKFILL	WAREHOUSE & LUNCH ROOM, 60'X50'X20'H								
	I-21-17 Total									
I-21-23	EARTHWORK, EXCAVATION									
I-21-23-1	EARTHWORK, EXCAVATION	WAREHOUSE & LUNCH ROOM, 60'X50'X20'H								
	I-21-23 Total									
	I-21 Total									
I-22	**CONCRETE**									
I-22-13	CONCRETE									
I-22-13-1	CONCRETE	WAREHOUSE & LUNCH ROOM, 60'X50'X20'H								
	I-22-13 Total									
I-22-17	FORMWORK									
I-22-17-1	FORMWORK	WAREHOUSE & LUNCH ROOM, 60'X50'X20'H								
	I-22-17 Total									
I-22-25	REINFORCING									
I-22-25-1	REINFORCING	WAREHOUSE & LUNCH ROOM, 60'X50'X20'H								
	I-22-25 Total									
	I-22 Total									
I-24	**ARCHITECTURAL**									
I-24-31	MISCELLANEOUS									
I-24-31-1	MISCELLANEOUS	WAREHOUSE & LUNCH ROOM SHELVING								
	I-24-31 Total									
I-24-35	PRE-ENGINEERED BUILDING									
I-24-35-1	PRE-ENGINEERED BUILDING	60'X50'X20'H, INCLUDES SIDING, ROOFING, H&V, LIGHTING, WAREHOUSE & LUNCH ROOM								
	I-24-35 Total									
	I-24 Total									
	I Total									
J	**REMOVAL AND RELOCATION OF EXISTING EQUIPMENT AND INFRASTRUCTURE**									
J-11	**DEMOLITION WORK**									
J-11-22	CONCRETE									
J-11-22-1	CONCRETE	ASSUME PORTION OF FOUNDATIONS TO BE LEFT IN PLACE, EXISTING BAGHOUSE								

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	J-11-22 Total									
J-11-23	STEEL									
J-11-23-1	STEEL	EXISTING BAGHOUSE								
	J-11-23 Total									
J-11-26	DUCTWORK									
J-11-26-1	DUCTWORK	EXISTING BAGHOUSE								
	J-11-26 Total									
J-11-31	MECHANICAL EQUIPMENT									
J-11-31-1	MECHANICAL EQUIPMENT	EXISTING ID FANS								
J-11-31-2	MECHANICAL EQUIPMENT	BAGHOUSE								
	J-11-31 Total									
	J-11 Total									
J-21	**CIVIL WORK**									
J-21-17	EARTHWORK, BACKFILL									
J-21-17-1	EARTHWORK, BACKFILL	BEDDING FOR UNDERGROUND PIPING								
J-21-17-2	EARTHWORK, BACKFILL	BACKFILL FOR UNDERGROUND PIPING								
	J-21-17 Total									
J-21-25	EARTHWORK, EXCAVATION									
J-21-25-1	EARTHWORK, EXCAVATION	EXCAVATION FOR UNDERGROUND PIPING								
	J-21-25 Total									
	J-21 Total									
J-35	**PIPING**									
J-35-13										
J-35-13-1	LARGE BORE	8" ASHCOLITE, FLANGED, ASH LINE, ABOVE GROUND, RELOCATE-TEMPORARY PIPE								
J-35-13-2	LARGE BORE	4" HDPE SDR11, INCLUDES FITTINGS, SERVICE WATER, UNDER GROUND, RELOCATE EXISTING PIPE SUPPLY TO FA SILO								
J-35-13-3	LARGE BORE	PIPE SUPPORTS FOR RELOCATED PIPING, ABOVE GROUND								
	J-35-13 Total									
	J-35 Total									
	J Total									
K	**NON POWER PRODUCING ASSETS**									

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

ESTIMATE NO. : 30859B
PROJECT NO. : 12715.001
ISSUE DATE : 10/29/2010
PREP/REV : RCK / MNO
APPROVED : BJD

[TRADE SECRET DATA BEGINS

OTTER TAIL
BIG STONE STATION
DFGD
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
K-81	**NON POWER PRODUCING ASSETS**									
K-81-13	CONSTRUCTION EQUIPMENT									
K-81-13-1	CONSTRUCTION EQUIPMENT	HEAVY CRANE RENTAL NOT INCLUDED IN THE WAGE RATES. INCLUDES OPERATOR AND OILER								
K-81-13-2	CONSTRUCTION EQUIPMENT	FREIGHT FOR HEAVY CRANE								
K-81-13-3	CONSTRUCTION EQUIPMENT	BUILD AND TEAR DOWN								
	K-81-13 Total									
	K-81 Total									
	K Total									
90	**SUBTOTAL DIRECT & CONSTRUCTION INDIRECT COST**									
91	OTHER DIRECT & CONSTRUCTION INDIRECT COST									
91-1	SCAFFOLDING - % of ACCT NO. 90									
91-2A	COST DUE TO OVERTIME WORKING 5 -9 HOUR DAYS	95% OF BASE MANHOURS								
91-21A	COST DUE TO OVERTIME INEFFICIENCY - SPECIFY % INEFFICIENCY	95% OF BASE MANHOURS								
91-22A	COST DUE TO OVERTIME PAY @1.5 TIMES OVERTIME PAY RATE - SPECIFY % ADDITIONAL HOURS PAID ON ACTUAL HOURS WORKED									
91-23A	COST DUE TO OVERTIME - ADDITIONAL PER DIEM									
91-2B	COST DUE TO OVERTIME WORKING 7 -10 HOUR DAYS	5% OF BASE MANHOURS								
91-21B	COST DUE TO OVERTIME INEFFICIENCY - SPECIFY % INEFFICIENCY	5% OF BASE MANHOURS								
91-22B	COST DUE TO OVERTIME PAY @1.5 TIMES OVERTIME PAY RATE - SPECIFY % ADDITIONAL HOURS PAID ON ACTUAL HOURS WORKED									
91-23B	COST DUE TO OVERTIME - ADDITIONAL PER DIEM									
91-3	PER DIEM									
91-4	CONSUMABLES - % of ACCT NO. 90									
91-5	FREIGHT ON MATERIAL - % of ACCT NO. 90									
91-6	FREIGHT ON EQUIPMENT - % of ACCT NO. 90									
91-7	SALES TAX - % of ACCT NO. 90	4% SALES TAX ON EQUIPMENT, MATERIAL AND LABOR, PLUS 2% EXCISE TAX ON CONTRACTOR'S GROSS RECEIPTS EXCLUDING OWNER PURCHASED MAJOR MATERIAL WHICH ARE CALCULATED AT 4%								

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

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APPROVED : BJD

[TRADE SECRET DATA BEGINS

OTTER TAIL
BIG STONE STATION
DFGD
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
91-9	CONTRACTOR'S GENERAL AND ADMINISTRATION EXPENSE - % of ACCT NO. 90									
91-10	CONTRACTOR'S PROFIT - % of ACCT NO. 90									
	91 - SUBTOTAL									
92	**TOTAL DIRECT & CONSTRUCTION INDIRECT COST**									
93	INDIRECT COST									
93-1	ENGINEERING, PROCUREMENT, & PROJECT SERVICES - % of ACCT NO. 92									
93-2	CONSTRUCTION MANAGEMENT SUPPORT - % of ACCT NO. 92									
93-3	S-U / COMMISSIONING - % of ACCT NO. 92									
93-3	START-UP SPARE PARTS									
93-4	EXCESS LIABILITY INSURANCE	AT 1% OF TOTAL DIRECT COST								
93-4	SALES TAX ON INDIRECTS	APPLIED SALES TAX ONLY. ASSUMED EXCISE TAX IS NOT APPLICABLE ON INDIRECTS								
93-5	OWNERS COST - Allowance									
93-5	OWNERS COST - 2 NEW SCRAPERS	NOT INCLUDED								
93-6	EPC FEE - NOT INCLUDED									
	93 - TOTAL INDIRECT COSTS									
94	**TOTAL CONTINGENCY**									
94-1	CONTINGENCY ON EQUIPMENT									
94-2	CONTINGENCY ON MATERIAL									
94-3	CONTINGENCY ON LABOR									
94-4	CONTINGENCY ON INDIRECT									
95	**TOTAL ESCALATION**									
95-1	ESCALATION ON EQUIPMENT									
95-2	ESCALATION ON MATERIAL									
95-3	ESCALATION ON LABOR									
95-4	ESCALATION ON INDIRECT									
96	TOTAL CONSTRUCTION COST									
97	INTEREST DURING CONSTRUCTION	BY OTP								

TRADE SECRET DATA ENDS]

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OTTER TAIL
BIG STONE STATION
DFGD
CONCEPTUAL COST ESTIMATE

[TRADE SECRET DATA BEGINS

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR: TRADE SECRET DATA ENDS]

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
98	**TOTAL PROJECT COST**									**303,694,800**

Schedule

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

ACI Estimate

SARGENT & LUNDY

ESTIMATE NO. : 30918A
PROJECT NO. : 12715.001
ISSUE DATE : 10/29/2010
PREP/REV : RCK / MNO
APPROVED : BJD

OTTER TAIL
BIG STONE STATION
ACTIVATED CARBON INJECTION SYSTEM
CONCEPTUAL COST ESTIMATE

[TRADE SECRET DATA BEGINS

CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
A	ACTIVATED CARBON INJECTION				
A -21	CIVIL WORK				
A -21-17 Total	EARTHWORK, BACKFILL				
A -21-23 Total	EARTHWORK, EXCAVATION				
A -21 Total	CIVIL WORK				
A -22	CONCRETE				
A -22-13 Total	CONCRETE				
A -22-15 Total	EMBEDMENT				
A -22-17 Total	FORMWORK				
A -22-25 Total	REINFORCING				
A -22 Total	CONCRETE				
A -23	STEEL				
A -23-25 Total	ROLLED SHAPE - STRUCTURAL STEEL				
A -23 Total	STEEL				
A -24	ARCHITECTURAL				
A -24-35 Total	PRE-ENGINEERED BUILDING				
A -24 Total	ARCHITECTURAL				
A -31	MECHANICAL EQUIPMENT				
A -31-51 Total	ACTIVATED CARBON INJECTION				
A -31 Total	MECHANICAL EQUIPMENT				
A Total	ACTIVATED CARBON INJECTION				
B	MECHANICAL - BALANCE OF PLANT				
B-35	PIPING				
B-35-13 Total	LARGE BORE				
B-35-15 Total	SMALL BORE				
B-35 Total	PIPING				
B Total	MECHANICAL - BALANCE OF PLANT				
C	ELECTRICAL - AUXILIARY POWER AND BALANCE OF PLANT ELECTRICAL WORK				
C-41	ELECTRICAL EQUIPMENT				
C-41-17 Total	COMMUNICATION SYSTEM				
C-41-31 Total	GROUNDING				
C-41-35 Total	LIGHTNING PROTECTION				
C-41-45 Total	MOTOR CONTROL CENTER (MCC)				
C-41-47 Total	PANEL: CONTROL, DISTRIBUTION, & RELAY				
C-41-51 Total	POWER TRANSFORMER				
C-41 Total	ELECTRICAL EQUIPMENT				
C-42	RACEWAY, CABLE TRAY, & CONDUIT				
C-42-13 Total	CABLE TRAY				
C-42-15 Total	CONDUITS				
C-42-17 Total	CONDUIT BOX				
C-42 Total	RACEWAY, CABLE TRAY, & CONDUIT				
C-43	CABLE				
C-43-13 Total	CONTROL & INSTRUMENT CABLE				

TRADE SECRET DATA ENDS]

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OTTER TAIL
BIG STONE STATION
ACTIVATED CARBON INJECTION SYSTEM
CONCEPTUAL COST ESTIMATE

[TRADE SECRET DATA BEGINS

CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
C-43-17 Total	LOW VOLTAGE POWER CABLE & TERMINATIONS				
C-43 Total	CABLE				
C-44	CONTROL & INSTRUMENTATION				
C-44-13 Total	CONTROL SYSTEM				
C-44-21 Total	INSTRUMENT				
C-44 Total	CONTROL & INSTRUMENTATION				
C Total	ELECTRICAL - AUXILIARY POWER AND BALANCE OF PLANT ELECTRICAL WORK				
D	NON POWER PRODUCING ASSETS				
D-81	NON POWER PRODUCING ASSETS				
D-81-13 Total	CONSTRUCTION EQUIPMENT				
D-81 Total	NON POWER PRODUCING ASSETS				
D Total	NON POWER PRODUCING ASSETS				
90	**SUBTOTAL DIRECT & CONSTRUCTION INDIRECT COST**				
91	OTHER DIRECT & CONSTRUCTION INDIRECT COST				
91-1	SCAFFOLDING - % of ACCT NO. 90				
91-2A	COST DUE TO OVERTIME WORKING 5 -9 HOUR DAYS				
91-21A	COST DUE TO OVERTIME INEFFICIENCY - SPECIFY % INEFFICIENCY				
91-22A	COST DUE TO OVERTIME PAY @1.5 TIMES OVERTIME PAY RATE - SPECIFY % ADDITIONAL HOURS PAID ON ACTUAL HOURS WORKED				
91-23A	COST DUE TO OVERTIME - ADDITIONAL PER DIEM				
91-3	PER DIEM				
91-4	CONSUMABLES - % of ACCT NO. 90				
91-5	FREIGHT ON MATERIAL - % of ACCT NO. 90				
91-6	FREIGHT ON EQUIPMENT - % of ACCT NO. 90				
91-7	SALES TAX - % of ACCT NO. 90				
91-9	CONTRACTOR'S GENERAL AND ADMINISTRATION EXPENSE - % of ACCT NO. 90				
91-10	CONTRACTOR'S PROFIT - % of ACCT NO. 90				
	91 - SUBTOTAL				
92	**TOTAL DIRECT & CONSTRUCTION INDIRECT COST**				
93	INDIRECT COST				
93-1	ENGINEERING, PROCUREMENT, & PROJECT SERVICES - % of ACCT NO. 92				
93-2	CONSTRUCTION MANAGEMENT SUPPORT - % of ACCT NO. 92				
93-3	S-U / COMMISSIONING - % of ACCT NO. 92				
93-3	START-UP SPARE PARTS				

TRADE SECRET DATA ENDS]

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OTTER TAIL
BIG STONE STATION
ACTIVATED CARBON INJECTION SYSTEM
CONCEPTUAL COST ESTIMATE

[TRADE SECRET DATA BEGINS

CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
93-4	EXCESS LIABILITY INSURANCE				
93-4	SALES TAX ON INDIRECTS				
93-5	OWNERS COST - NOT INCLUDED				
93-6	EPC FEE - NOT INCLUDED				
	93 - TOTAL INDIRECT COSTS				
94	**TOTAL CONTINGENCY**				
94-1	CONTINGENCY ON EQUIPMENT				
94-2	CONTINGENCY ON MATERIAL				
94-3	CONTINGENCY ON LABOR				
94-4	CONTINGENCY ON INDIRECT				
95	**TOTAL ESCALATION**				
95-1	ESCALATION ON EQUIPMENT				
95-2	ESCALATION ON MATERIAL				
95-3	ESCALATION ON LABOR				
95-4	ESCALATION ON INDIRECT				
96	**TOTAL CONSTRUCTION COST**				
97	INTEREST DURING CONSTRUCTION				
98	**TOTAL PROJECT COST**				**5,012,700**

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

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OTTER TAIL
BIG STONE STATION
ACTIVATED CARBON INJECTION SYSTEM
CONCEPTUAL COST ESTIMATE

[TRADE SECRET DATA BEGINS

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
A	**ACTIVATED CARBON INJECTION**									
A -21	**CIVIL WORK**									
A -21-17	EARTHWORK, BACKFILL									
A -21-17-1	EARTHWORK, BACKFILL	FOUNDATIONS FOR ACI SILO								
A -21-17-2	EARTHWORK, BACKFILL	FOUNDATIONS FOR ELECTRICAL EQUIPMENT ENCLOSURE, (15'x20'x20'H)								
	A -21-17 Total									
A -21-23	EARTHWORK, EXCAVATION									
A -21-23-1	EARTHWORK, EXCAVATION	FOUNDATIONS FOR ACI SILO								
A -21-23-2	EARTHWORK, EXCAVATION	FOUNDATIONS FOR ELECTRICAL EQUIPMENT ENCLOSURE, (15'x20'x20'H)								
	A -21-23 Total									
	A -21 Total									
A -22	**CONCRETE**									
A -22-13	CONCRETE									
A -22-13-1	CONCRETE	FOUNDATIONS FOR ACI SILO								
A -22-13-2	CONCRETE	FOUNDATIONS FOR ELECTRICAL EQUIPMENT ENCLOSURE, (15'x20'x20'H)								
	A -22-13 Total									
A -22-15	EMBEDMENT									
A -22-15-1	EMBEDMENT	FOUNDATIONS FOR ACI SILO								
A -22-15-2	EMBEDMENT	FOUNDATIONS FOR ELECTRICAL EQUIPMENT ENCLOSURE, (15'x20'x20'H)								
	A -22-15 Total									
A -22-17	FORMWORK									
A -22-17-1	FORMWORK	FOUNDATIONS FOR ACI SILO								
A -22-17-2	FORMWORK	FOUNDATIONS FOR ELECTRICAL EQUIPMENT ENCLOSURE, (15'x20'x20'H)								
	A -22-17 Total									
A -22-25	REINFORCING									
A -22-25-1	REINFORCING	FOUNDATIONS FOR ACI SILO								
A -22-25-2	REINFORCING	FOUNDATIONS FOR ELECTRICAL EQUIPMENT ENCLOSURE, (15'x20'x20'H)								
	A -22-25 Total									
	A -22 Total									
A -23	**STEEL**									
A -23-25	ROLLED SHAPE - STRUCTURAL STEEL									

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

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[TRADE SECRET DATA BEGINS

OTTER TAIL
BIG STONE STATION
ACTIVATED CARBON INJECTION SYSTEM
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
A -23-25-1	STRUCTURAL STEEL	SUPPORT STEEL FOR ACI SILO SUPPLIED BY OEM, INSTALLED BY GWC								
	A -23-25 Total									
	A -23 Total									
A -24	**ARCHITECTURAL**									
A -24-35	PRE-ENGINEERED BUILDING									
A -24-35-1	PRE-ENGINEERED BUILDING	15'x20'x20'H ENCLOSURE HOUSES MCC'S AND CONTROL PANELS, H&V AND LIGHTING								
	A -24-35 Total									
	A -24 Total									
A -31	**MECHANICAL EQUIPMENT**									
A -31-51	ACTIVATED CARBON INJECTION									
A -31-51-1	ACTIVATED CARBON INJECTION	TRUCK UNLOADING PANEL, SILO AND FEED SYSTEM EQUIPMENT INCLUDING UNLOADING PIPING, BLOWERS, FEEDERS, BIN VENTS, STAIRWAY, INJECTION MANIFOLD/LANCES AND PORTS, CFD MODELING, SILO INSTRUMENTATION, (14" DIAMETER SILO)								
	A -31-51 Total									
	A -31 Total									
	A Total									
B	**MECHANICAL - BALANCE OF PLANT**									
B-35	**PIPING**									
B-35-13	LARGE BORE									
B-35-13-1	LARGE BORE	3" CS, SCH 40, INCLUDES FITTINGS, ACI								
B-35-13-2	LARGE BORE	4" CS, SCH 40, INCLUDES FITTINGS, ACI PIPING								
B-35-13-3	LARGE BORE VALVE	4" CS GATE CLASS 150								
B-35-13-4	LARGE BORE VALVE	3" CS GATE CLASS 150								
B-35-13-5	LARGE BORE PIPE SUPPORTS									
	B-35-13 Total									
B-35-15	SMALL BORE									
B-35-15-1	SMALL BORE	2" CS, SCH 80, INCLUDES FITTINGS, ACI SYSTEM								

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

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OTTER TAIL
BIG STONE STATION
ACTIVATED CARBON INJECTION SYSTEM
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
B-35-15-2	SMALL BORE	SMALL BORE VALVES, CS WELDED								
B-35-15-3	SMALL BORE	INSTRUMENT TUBING								
B-35-15-4	SMALL BORE PIPE SUPPORTS									
	B-35-15 Total									
	B-35 Total									
	B Total									
C	**ELECTRICAL - AUXILIARY POWER AND BALANCE OF PLANT ELECTRICAL WORK**									
C-41	**ELECTRICAL EQUIPMENT**									
C-41-17	COMMUNICATION SYSTEM									
C-41-17-1	COMMUNICATION SYSTEM	PA / PAGE PARTY EXTENSION SYSTEM, ACI SYSTEM								
C-41-17-2	COMMUNICATION SYSTEM	DATA COM EXTENSION SYSTEM - ACI SYSTEM								
C-41-17-3	COMMUNICATION SYSTEM	TELEPHONE EXTENSION SYSTEM - ACI SYSTEM								
	C-41-17 Total									
C-41-31	GROUNDING									
C-41-31-1	GROUNDING	GROUNDING; INCLUDING GND ROD, BARE WIRE & TERMINATION / CAD WELD - FOR THE ENTIRE PROJECT AREA INCLUDING AMMONIA TANK FARM								
	C-41-31 Total									
C-41-35	LIGHTNING PROTECTION									
C-41-35-1	LIGHTNING PROTECTION	#500 KCMIL								
C-41-35-2	LIGHTNING PROTECTION	#4/0 BARE COPPER								
C-41-35-3	LIGHTNING PROTECTION	CAD WELD & WIRE TERMINATION								
	C-41-35 Total									
C-41-45	MOTOR CONTROL CENTER (MCC)									
C-41-45-1	MOTOR CONTROL CENTER (MCC)	MCC-400A, 480V, 3 PHASE; AUXILIARY POWER MODIFICATIONS								
	C-41-45 Total									
C-41-47	PANEL: CONTROL, DISTRIBUTION, & RELAY									
C-41-47-1	PANEL: CONTROL, DISTRIBUTION, & RELAY	PROTECTIVE RELAY PANELS & MISC HDWR (ALLOWANCE)								
	C-41-47 Total									
C-41-51	POWER TRANSFORMER									

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

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OTTER TAIL
BIG STONE STATION
ACTIVATED CARBON INJECTION SYSTEM
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
C-41-51-1	POWER TRANSFORMER	LIGHTING TRANSFORMERS 45KVA, 480V, 3 PHASE, LOW VOLTAGE XFMR; AUXILIARY POWER MODIFICATIONS								
	C-41-51 Total									
	C-41 Total									
C-42	**RACEWAY, CABLE TRAY, & CONDUIT**									
C-42-13	CABLE TRAY									
C-42-13-1	CABLE TRAY	CABLE TRAY, 24" LIME SILO & REAGENT PREP BUILDING, RECYCLE BUILDING, BAGHOUSE ENCLOSURE, WATER TREATMENT BUILDING, WASTE BLOWER BUILDING & ELECTRICAL EQUIPMENT BUILDINGS								
	C-42-13 Total									
C-42-15	CONDUITS									
C-42-15-1	CONDUITS	MISC SIZES (3/4" to 3") ENTIRE PROJECT AREA INCLUDING AMMONIA TANK FARM								
	C-42-15 Total									
C-42-17	CONDUIT BOX									
C-42-17-1	CONDUIT BOX	MISC. JUNCTION BOXES & PULL BOXES; ENTIRE PROJECT AREA INCLUDING AMMONIA TANK FARM								
	C-42-17 Total									
	C-42 Total									
C-43	**CABLE**									
C-43-13	CONTROL & INSTRUMENT CABLE									
C-43-13-1	CONTROL & INSTRUMENT CABLE	2/C #14;								
C-43-13-2	CONTROL & INSTRUMENT CABLE	2 PR, #16 TW SHLD;								
C-43-13-3	CONTROL & INSTRUMENT CABLE	FIBER OPTIC CABLE, 24 STRAND;								
C-43-13-4	CONTROL & INSTRUMENT CABLE	CAT 5E								
C-43-13-5	CONTROL & INSTRUMENT CABLE	INSTRUMENTATION CABLE TERMINATIONS								
	C-43-13 Total									
C-43-17	LOW VOLTAGE POWER CABLE & TERMINATIONS									
C-43-17-1	LOW VOLTAGE POWER CABLE	3/C, #4/0, 600 V								
C-43-17-2	LOW VOLTAGE POWER CABLE	3/C, #1/0, 600 V								

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

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OTTER TAIL
BIG STONE STATION
ACTIVATED CARBON INJECTION SYSTEM
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
C-43-17-3	LOW VOLTAGE POWER CABLE TERMINATIONS	600V POWER & CONTROL CABLE TERMINATIONS								
	C-43-17 Total									
	C-43 Total									
C-44	**CONTROL & INSTRUMENTATION**									
C-44-13	CONTROL SYSTEM									
C-44-13-1	CONTROL SYSTEM	PLC BASED CONTROLS. DFGD DCS SYSTEM WILL HAVE CAPABILITY TO COMMUNCATE WITH THE PLC								
C-44-13-2	VENDOR TECHNICAL ADVISORY SERVICE	NOT REQUIRED FOR PLC								
	C-44-13 Total									
C-44-21	INSTRUMENT									
C-44-21-1	INSTRUMENT	LOCALLY MOUNTED INSTRUMENTS								
	C-44-21 Total									
	C-44 Total									
	C Total									
D	NON POWER PRODUCING ASSETS									
D-81	NON POWER PRODUCING ASSETS									
D-81-13	CONSTRUCTION EQUIPMENT									
D-81-13-1	CONSTRUCTION EQUIPMENT	HEAVY CRANE RENTAL NOT INCLUDED IN THE WAGE RATES. INCLUDES OPREATOR AND OILER								
D-81-13-2	CONSTRUCTION EQUIPMENT	FREIGHT FOR HEAVY CRANE								
D-81-13-3	CONSTRUCTION EQUIPMENT	BUILD AND TEAR DOWN								
	D-81-13 Total									
	D-81 Total									
	D Total									
90	**SUBTOTAL DIRECT & CONSTRUCTION INDIRECT COST**									
91	OTHER DIRECT & CONSTRUCTION INDIRECT COST									
91-1	SCAFFOLDING - % of ACCT NO. 90									
91-2A	COST DUE TO OVERTIME WORKING 5 -9 HOUR DAYS	95% OF BASE MANHOURS								
91-21A	COST DUE TO OVERTIME INEFFICIENCY - SPECIFY % INEFFICIENCY	95% OF BASE MANHOURS								
91-22A	COST DUE TO OVERTIME PAY @1.5 TIMES OVERTIME PAY RATE - SPECIFY % ADDITIONAL HOURS PAID ON ACTUAL HOURS WORKED									

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

ESTIMATE NO. : 30918A
PROJECT NO. : 12715.001
ISSUE DATE : 10/29/2010
PREP/REV : RCK / MNO
APPROVED : BJD

[TRADE SECRET DATA BEGINS

OTTER TAIL
BIG STONE STATION
ACTIVATED CARBON INJECTION SYSTEM
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
91-23A	COST DUE TO OVERTIME - ADDITIONAL PER DIEM									
91-3	PER DIEM									
91-4	CONSUMABLES - % of ACCT NO. 90									
91-5	FREIGHT ON MATERIAL - % of ACCT NO. 90									
91-6	FREIGHT ON EQUIPMENT - % of ACCT NO. 90									
91-7	SALES TAX - % of ACCT NO. 90	4% SALES TAX ON EQUIPMENT, MATERIAL AND LABOR, PLUS 2% EXCISE TAX ON CONTRACTOR'S GROSS RECEIPTS EXCLUDING OWNER PURCHASED MAJOR MATERIAL WHICH ARE CALCULATED AT 4%								
91-9	CONTRACTOR'S GENERAL AND ADMINISTRATION EXPENSE - % of ACCT NO. 90									
91-10	CONTRACTOR'S PROFIT - % of ACCT NO. 90									
	91 - SUBTOTAL									
92	**TOTAL DIRECT & CONSTRUCTION INDIRECT COST**									
93	INDIRECT COST									
93-1	ENGINEERING, PROCUREMENT, & PROJECT SERVICES - % of ACCT NO. 92									
93-2	CONSTRUCTION MANAGEMENT SUPPORT - % of ACCT NO. 92									
93-3	S-U / COMMISSIONING - % of ACCT NO. 92									
93-3	START-UP SPARE PARTS									
93-4	EXCESS LIABILITY INSURANCE	AT 1% OF TOTAL DIRECT COST								
93-4	SALES TAX ON INDIRECTS	APPLIED SALES TAX ONLY. ASSUMED EXCISE TAX IS NOT APPLICABLE ON INDIRECTS								
93-5	OWNERS COST - NOT INCLUDED									
93-6	EPC FEE - NOT INCLUDED									
	93 - TOTAL INDIRECT COSTS									
94	**TOTAL CONTINGENCY**									
94-1	CONTINGENCY ON EQUIPMENT									

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

ESTIMATE NO. : 30918A
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[TRADE SECRET DATA BEGINS

OTTER TAIL
BIG STONE STATION
ACTIVATED CARBON INJECTION SYSTEM
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
94-2	CONTINGENCY ON MATERIAL									
94-3	CONTINGENCY ON LABOR									
94-4	CONTINGENCY ON INDIRECT									
95	**TOTAL ESCALATION**									
95-1	ESCALATION ON EQUIPMENT									
95-2	ESCALATION ON MATERIAL									
95-3	ESCALATION ON LABOR									
95-4	ESCALATION ON INDIRECT									
96	**TOTAL CONSTRUCTION COST**									
97	INTEREST DURING CONSTRUCTION	BY OTP								
98	**TOTAL PROJECT COST**									**5,012,700**

TRADE SECRET DATA ENDS]

Water Estimate

SARGENT & LUNDY

ESTIMATE NO. : 30919A
PROJECT NO. : 12715.001
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APPROVED : BJD

OTTER TAIL
BIG STONE STATION
WATER TREATMENT SYSTEM
CONCEPTUAL COST ESTIMATE

[TRADE SECRET DATA BEGINS

CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
A	WATER TREATMENT				
A-21	CIVIL WORK				
A-21-17 Total	EARTHWORK, BACKFILL				
A-21-23 Total	EARTHWORK, EXCAVATION				
A-21 Total	CIVIL WORK				
A-22	CONCRETE				
A-22-13 Total	CONCRETE				
A-22-15 Total	EMBEDMENT				
A-22-17 Total	FORMWORK				
A-22-25 Total	REINFORCING				
A-22 Total	CONCRETE				
A-24	ARCHITECTURAL				
A-24-35 Total	PRE-ENGINEERED BUILDING				
A-24 Total	ARCHITECTURAL				
A-31	MECHANICAL EQUIPMENT				
A-31-93 Total	WATER TREATMENT SYSTEM				
A-31 Total	MECHANICAL EQUIPMENT				
A-34	HVAC				
A-34-53 Total	UNIT HEATER				
A-34 Total	HVAC				
A-41	ELECTRICAL EQUIPMENT				
A-41-37 Total	LIGHTING ACCESSORY (FIXTURE)				
A-41 Total	ELECTRICAL EQUIPMENT				
A Total	WATER TREATMENT				
B	MECHANICAL - BALANCE OF PLANT				
B-35	PIPING				
B-35-13 Total					
B-35-15 Total					
B-35 Total	PIPING				
B-41	ELECTRICAL EQUIPMENT				
B-41-33 Total	HEAT TRACING				
B-41 Total	ELECTRICAL EQUIPMENT				
B Total	MECHANICAL - BALANCE OF PLANT				
C	ELECTRICAL - AUXILIARY POWER AND BALANCE OF PLANT ELECTRICAL WORK				
C-41	ELECTRICAL EQUIPMENT				
C-41-17 Total	COMMUNICATION SYSTEM				
C-41-31 Total	GROUNDING				
C-41-35 Total	LIGHTNING PROTECTION				
C-41-45 Total	MOTOR CONTROL CENTER (MCC)				
C-41-47 Total	PANEL: CONTROL, DISTRIBUTION, & RELAY				
C-41-51 Total	POWER TRANSFORMER				
C-41 Total	ELECTRICAL EQUIPMENT				
C-42	RACEWAY, CABLE TRAY, & CONDUIT				

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

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PREP/REV : RCK / MNO
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OTTER TAIL
BIG STONE STATION
WATER TREATMENT SYSTEM
CONCEPTUAL COST ESTIMATE

[TRADE SECRET DATA BEGINS

CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
C-42-13 Total	CABLE TRAY				
C-42-15 Total	CONDUITS				
C-42-17 Total	CONDUIT BOX				
C-42 Total	RACEWAY, CABLE TRAY, & CONDUIT				
C-43	CABLE				
C-43-13 Total	CONTROL & INSTRUMENT CABLE				
C-43-17 Total	LOW VOLTAGE POWER CABLE & TERMINATIONS				
C-43 Total	CABLE				
C-44	CONTROL & INSTRUMENTATION				
C-44-13 Total	CONTROL SYSTEM				
C-44-21 Total	INSTRUMENT				
C-44 Total	CONTROL & INSTRUMENTATION				
C Total	ELECTRICAL - AUXILIARY POWER AND BALANCE OF PLANT ELECTRICAL WORK				
D	NON POWER PRODUCING ASSETS				
D-81	NON POWER PRODUCING ASSETS				
D-81-13 Total	CONSTRUCTION EQUIPMENT				
D-81 Total	NON POWER PRODUCING ASSETS				
D Total	NON POWER PRODUCING ASSETS				
90	**SUBTOTAL DIRECT & CONSTRUCTION INDIRECT COST**				
91	OTHER DIRECT & CONSTRUCTION INDIRECT COST				
91-1	SCAFFOLDING - % of ACCT NO. 90				
91-2A	COST DUE TO OVERTIME WORKING 5 -9 HOUR DAYS				
91-21A	COST DUE TO OVERTIME INEFFICIENCY - SPECIFY % INEFFICIENCY				
91-22A	COST DUE TO OVERTIME PAY @1.5 TIMES OVERTIME PAY RATE - SPECIFY % ADDITIONAL HOURS PAID ON ACTUAL HOURS WORKED				
91-23A	COST DUE TO OVERTIME - ADDITIONAL PER DIEM				
91-3	PER DIEM				
91-4	CONSUMABLES - % of ACCT NO. 90				
91-5	FREIGHT ON MATERIAL - % of ACCT NO. 90				
91-6	FREIGHT ON EQUIPMENT - % of ACCT NO. 90				
91-7	SALES TAX - % of ACCT NO. 90				
91-9	CONTRACTOR'S GENERAL AND ADMINISTRATION EXPENSE - % of ACCT NO. 90				
91-10	CONTRACTOR'S PROFIT - % of ACCT NO. 90				
	91 - SUBTOTAL				
92	**TOTAL DIRECT & CONSTRUCTION INDIRECT COST**				
93	INDIRECT COST				
93-1	ENGINEERING, PROCUREMENT, & PROJECT SERVICES - % of ACCT NO. 92				

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

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OTTER TAIL
BIG STONE STATION
WATER TREATMENT SYSTEM
CONCEPTUAL COST ESTIMATE

[TRADE SECRET DATA BEGINS

CODE OF ACCOUNT	DESCRIPTION A	EQUIPMENT COST	MATERIAL COST	LABOR COST	TOTAL COST
93-2	CONSTRUCTION MANAGEMENT SUPPORT - % of ACCT NO. 92				
93-3	S-U / COMMISSIONING - % of ACCT NO. 92				
93-3	START-UP SPARE PARTS				
93-4	EXCESS LIABILITY INSURANCE				
93-4	SALES TAX ON INDIRECTS				
93-5	OWNERS COST - NOT INCLUDED				
93-6	EPC FEE - NOT INCLUDED				
	93 - TOTAL INDIRECT COSTS				
94	TOTAL CONTINGENCY				
94-1	CONTINGENCY ON EQUIPMENT				
94-2	CONTINGENCY ON MATERIAL				
94-3	CONTINGENCY ON LABOR				
94-4	CONTINGENCY ON INDIRECT				
95	TOTAL ESCALATION				
95-1	ESCALATION ON EQUIPMENT				
95-2	ESCALATION ON MATERIAL				
95-3	ESCALATION ON LABOR				
95-4	ESCALATION ON INDIRECT				
96	**TOTAL CONSTRUCTION COST**				
97	INTEREST DURING CONSTRUCTION				
98	**TOTAL PROJECT COST**				**13,086,900**

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

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[TRADE SECRET DATA BEGINS

OTTER TAIL
BIG STONE STATION
WATER TREATMENT SYSTEM
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
A	**WATER TREATMENT**									
A-21	**CIVIL WORK**									
A-21-17	EARTHWORK, BACKFILL									
A-21-17-1	EARTHWORK, BACKFILL	WATER TREATMENT BUILDING , 120'X100'X40'H								
	A-21-17 Total									
A-21-23	EARTHWORK, EXCAVATION									
A-21-23-1	EARTHWORK, EXCAVATION	WATER TREATMENT BUILDING , 120'X100'X40'H								
	A-21-23 Total									
	A-21 Total									
A-22	**CONCRETE**									
A-22-13	CONCRETE									
A-22-13-1	CONCRETE	WATER TREATMENT BUILDING , 120'X100'X40'H								
	A-22-13 Total									
A-22-15	EMBEDMENT									
A-22-15-1	EMBEDMENT	WATER TREATMENT BUILDING , 120'X100'X40'H								
	A-22-15 Total									
A-22-17	FORMWORK									
A-22-17-1	FORMWORK	WATER TREATMENT BUILDING , 120'X100'X40'H								
	A-22-17 Total									
A-22-25	REINFORCING									
A-22-25-1	REINFORCING	WATER TREATMENT BUILDING , 120'X100'X40'H								
	A-22-25 Total									
	A-22 Total									
A-24	**ARCHITECTURAL**									
A-24-35	PRE-ENGINEERED BUILDING									
A-24-35-1	PRE-ENGINEERED BUILDING	WATER TREATMENT BUILDING 120'X100'X 40' HIGH, INCLUDES STEEL, SIDING, ROOFING, H&V, LIGHTING								
	A-24-35 Total									
	A-24 Total									
A-31	**MECHANICAL EQUIPMENT**									
A-31-93	WATER TREATMENT SYSTEM									

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

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OTTER TAIL
BIG STONE STATION
WATER TREATMENT SYSTEM
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
A-31-93-1	WATER TREATMENT SYSTEM	INCLUDING: COAGULANT DOSING SYSTEM BACKWASHABLE STRAINERS ULTRA FILTRATION SYSTEM BACKWASH PUMPS FILTERED STORAGE TANK (5000 GAL) SODIUM BISULFATE DOSING SYSTEM ANTISCALANT DOSING SYSTEM CARTRIDGE FILTERS CAUSTIC DOSING SYSTEM FIRST PASS RO BOOSTER PUMPS								
	A-31-93 Total									
	A-31 Total									
A-34	**HVAC**									
A-34-53	UNIT HEATER									
A-34-53-1	STEAM UNIT HEATER - WALL MOUNT, 150,000 BTU EA	WATER TREATMENT BUILDING. INCLUDES 2 UNIT HEATERS AND 400 FT PIPING ALLOWANCE								
	A-34-53 Total									
	A-34 Total									
A-41	**ELECTRICAL EQUIPMENT**									
A-41-37	LIGHTING ACCESSORY (FIXTURE)									
A-41-37-1	LIGHTING ACCESSORY (FIXTURE)	BUILDING SERVICES, H&V AND LIGHTING, WATER TREATMENT BUILDING								
	A-41-37 Total									
	A-41 Total									
	A Total									
B	**MECHANICAL - BALANCE OF PLANT**									
B-35	**PIPING**									
B-35-13										
B-35-13-1	LARGE BORE	6" HDPE SDR11, INCLUDES FITTINGS, UNDERGROUND, CLS EFFLUENT TO WATER TREATMENT BUILDING; MAKE UP WATER								

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

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OTTER TAIL
BIG STONE STATION
WATER TREATMENT SYSTEM
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
B-35-13-2	LARGE BORE	6" HDPE SDR11, INCLUDES FITTINGS, UNDERGROUND, WATER TREATMENT BUILDING RO REJECT TO RECYCLE MU TANK; MAKEUP WATER								
B-35-13-3	LARGE BORE	6" HDPE SDR11, INCLUDES FITTINGS, UNDERGROUND, WATER TREATMENT BUILDING RO REJECT TO SLUDGE POND; MAKEUP WATER								
B-35-13-4	LARGE BORE	PIPE SUPPORTS FOR RO PERMEATE, INSIDE WATER TREATMENT BUILDING AND TURBINE BUILDING; MAKEUP WATER								
B-35-13-5	LARGE BORE	STEAM HEADER TO WATER TREATMENT BLDG 3" SCH 40 ON RACK								
B-35-13-6	LARGE BORE	SUPPORTS - STEAM HEADER TO WATER TREATMENT BLDG 3" SCH 40 ON RACK								
B-35-13-7	LARGE BORE	3" CS GATE CLASS 150								
B-35-13-8	LARGE BORE	3" CS CONTROL VALVE-PNEUMATIC								
B-35-13-9	LARGE BORE PIPE SUPPORTS									
	B-35-13 Total									
B-35-15										
B-35-15-1	SMALL BORE	1" BRONZE BALL								
B-35-15-2	SMALL BORE	2" BRONZE, BALL								
B-35-15-3	SMALL BORE	SMALL BORE VALVES, CS WELDED								
B-35-15-4	SMALL BORE	2" GA CS, SCH 40, INCLUDES FITTINGS, U/G , DOMESTIC WATER								
B-35-15-5	SMALL BORE	INSTRUMENT TUBING								
B-35-15-6	SMALL BORE PIPE SUPPORTS									
	B-35-15 Total									
	B-35 Total									
B-41	**ELECTRICAL EQUIPMENT**									
B-41-33	HEAT TRACING									
B-41-33-1	HEAT TRACING	HEAT TRACING CABLE								

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

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OTTER TAIL
BIG STONE STATION
WATER TREATMENT SYSTEM
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
B-41-33-2	HEAT TRACING	POWER CONNECTOR AND OTHER ACCESSORIES INCLUDING THERMOSTATS FOR HEAT TRACING (BY ZONES)								
	B-41-33 Total									
	B-41 Total									
	B Total									
C	**ELECTRICAL - AUXILIARY POWER AND BALANCE OF PLANT ELECTRICAL WORK**									
C-41	**ELECTRICAL EQUIPMENT**									
C-41-17	COMMUNICATION SYSTEM									
C-41-17-1	COMMUNICATION SYSTEM	PA / PAGE PARTY EXTENSION SYSTEM, WATER TREATMENT BUILDING								
C-41-17-2	COMMUNICATION SYSTEM	DATA COM EXTENSION SYSTEM - WATER TREATMENT BUILDING								
C-41-17-3	COMMUNICATION SYSTEM	TELEPHONE EXTENSION SYSTEM - WATER TREATMENT BUILDING								
	C-41-17 Total									
C-41-31	GROUNDING									
C-41-31-1	GROUNDING	GROUNDING; INCLUDING GND ROD, BARE WIRE & TERMINATION / CAD WELD - FOR THE ENTIRE PROJECT AREA INCLUDING AMMONIA TANK FARM								
	C-41-31 Total									
C-41-35	LIGHTNING PROTECTION									
C-41-35-1	LIGHTNING PROTECTION	#500 KCMIL								
C-41-35-2	LIGHTNING PROTECTION	#4/0 BARE COPPER								
C-41-35-3	LIGHTNING PROTECTION	CAD WELD & WIRE TERMINATION								
	C-41-35 Total									
C-41-45	MOTOR CONTROL CENTER (MCC)									
C-41-45-1	MOTOR CONTROL CENTER (MCC)	MCC-400A, 480V, 3 PHASE; AUXILIARY POWER MODIFICATIONS								
	C-41-45 Total									
C-41-47	PANEL: CONTROL, DISTRIBUTION, & RELAY									
C-41-47-1	PANEL: CONTROL, DISTRIBUTION, & RELAY	PROTECTIVE RELAY PANELS & MISC HDWR (ALLOWANCE)								
	C-41-47 Total									

TRADE SECRET DATA ENDS]

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OTTER TAIL
BIG STONE STATION
WATER TREATMENT SYSTEM
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
C-41-51	POWER TRANSFORMER									
C-41-51-1	POWER TRANSFORMER	LIGHTING TRANSFORMERS 45KVA, 480V, 3 PHASE, LOW VOLTAGE XFMR; AUXILIARY POWER MODIFICATIONS								
	C-41-51 Total									
	C-41 Total									
C-42	**RACEWAY, CABLE TRAY, & CONDUIT**									
C-42-13	CABLE TRAY									
C-42-13-1	CABLE TRAY	CABLE TRAY, 24" WATER TREATMENT BUILDING								
	C-42-13 Total									
C-42-15	CONDUITS									
C-42-15-1	CONDUITS	MISC SIZES (3/4" to 3") ENTIRE PROJECT AREA INCLUDING AMMONIA TANK FARM								
	C-42-15 Total									
C-42-17	CONDUIT BOX									
C-42-17-1	CONDUIT BOX	MISC. JUNCTION BOXES & PULL BOXES; ENTIRE PROJECT AREA INCLUDING AMMONIA TANK FARM								
	C-42-17 Total									
	C-42 Total									
C-43	**CABLE**									
C-43-13	CONTROL & INSTRUMENT CABLE									
C-43-13-1	CONTROL & INSTRUMENT CABLE	2/C #14;								
C-43-13-3	CONTROL & INSTRUMENT CABLE	5/C, #14;								
C-43-13-3	CONTROL & INSTRUMENT CABLE	1PR #16 TW SHLD; 300 V								
C-43-13-4	CONTROL & INSTRUMENT CABLE	2 PR, #16 TW SHLD;								
C-43-13-5	CONTROL & INSTRUMENT CABLE	FIBER OPTIC CABLE, 24 STRAND;								
C-43-13-6	CONTROL & INSTRUMENT CABLE	CAT 5E								
C-43-13-7	CONTROL & INSTRUMENT CABLE	INSTRUMENTATION CABLE TERMINATIONS								
	C-43-13 Total									
C-43-17	LOW VOLTAGE POWER CABLE & TERMINATIONS									
C-43-17-1	LOW VOLTAGE POWER CABLE	3/C, #4/0, 600 V								
C-43-17-2	LOW VOLTAGE POWER CABLE	3/C, #1/0, 600 V								
C-43-17-3	LOW VOLTAGE POWER CABLE	3/C,#8 600 V								
C-43-17-4	LOW VOLTAGE POWER CABLE	3/C, #10, 600 V								

TRADE SECRET DATA ENDS]

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OTTER TAIL
BIG STONE STATION
WATER TREATMENT SYSTEM
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
C-43-17-5	LOW VOLTAGE POWER CABLE TERMINATIONS	600V POWER & CONTROL CABLE TERMINATIONS								
	C-43-17 Total									
	C-43 Total									
C-44	**CONTROL & INSTRUMENTATION**									
C-44-13	CONTROL SYSTEM									
C-44-13-1	CONTROL SYSTEM	PLC SYSTEM INCLUDED WITH WTARE TREATMENT EQUIPMENT								
C-44-13-2	VENDOR TECHNICAL ADVISORY SERVICE	NOT REQUIRED FOR PLC								
	C-44-13 Total									
C-44-21	INSTRUMENT									
C-44-21-1	INSTRUMENT	LOCALLY MOUNTED INSTRUMENTS								
	C-44-21 Total									
	C-44 Total									
	C Total									
D	NON POWER PRODUCING ASSETS									
D-81	NON POWER PRODUCING ASSETS									
D-81-13	CONSTRUCTION EQUIPMENT									
D-81-13-1	CONSTRUCTION EQUIPMENT	HEAVY CRANE RENTAL NOT INCLUDED IN THE WAGE RATES. INCLUDES OPREATOR AND OILER								
D-81-13-2	CONSTRUCTION EQUIPMENT	FREIGHT FOR HEAVY CRANE								
D-81-13-3	CONSTRUCTION EQUIPMENT	BUILD AND TEAR DOWN								
	D-81-13 Total									
	D-81 Total									
	D Total									
90	**SUBTOTAL DIRECT & CONSTRUCTION INDIRECT COST**									
91	OTHER DIRECT & CONSTRUCTION INDIRECT COST									
91-1	SCAFFOLDING - % of ACCT NO. 90									
91-2A	COST DUE TO OVERTIME WORKING 5 -9 HOUR DAYS	95% OF BASE MANHOURS								
91-21A	COST DUE TO OVERTIME INEFFICIENCY - SPECIFY % INEFFICIENCY	95% OF BASE MANHOURS								
91-22A	COST DUE TO OVERTIME PAY @1.5 TIMES OVERTIME PAY RATE - SPECIFY % ADDITIONAL HOURS PAID ON ACTUAL HOURS WORKED									
91-23A	COST DUE TO OVERTIME - ADDITIONAL PER DIEM									

TRADE SECRET DATA ENDS]

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OTTER TAIL
BIG STONE STATION
WATER TREATMENT SYSTEM
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
91-3	PER DIEM									
91-4	CONSUMABLES - % of ACCT NO. 90									
91-5	FREIGHT ON MATERIAL - % of ACCT NO. 90									
91-6	FREIGHT ON EQUIPMENT - % of ACCT NO. 90									
91-7	SALES TAX - % of ACCT NO. 90	4% SALES TAX ON EQUIPMENT, MATERIAL AND LABOR, PLUS 2% EXCISE TAX ON CONTRACTOR'S GROSS RECEIPTS								
91-9	CONTRACTOR'S GENERAL AND ADMINISTRATION EXPENSE - % of ACCT NO. 90									
91-10	CONTRACTOR'S PROFIT - % of ACCT NO. 90									
	91 - SUBTOTAL									
92	**TOTAL DIRECT & CONSTRUCTION INDIRECT COST**									
93	INDIRECT COST									
93-1	ENGINEERING, PROCUREMENT, & PROJECT SERVICES - % of ACCT NO. 92									
93-2	CONSTRUCTION MANAGEMENT SUPPORT - % of ACCT NO. 92									
93-3	S-U / COMMISSIONING - % of ACCT NO. 92									
93-3	START-UP SPARE PARTS									
93-4	EXCESS LIABILITY INSURANCE	AT 1% OF TOTAL DIRECT COST								
93-4	SALES TAX ON INDIRECTS	APPLIED SALES TAX ONLY. ASSUMED EXCISE TAX IS NOT APPLICABLE ON INDIRECTS								
93-5	OWNERS COST - NOT INCLUDED									
93-6	EPC FEE - NOT INCLUDED									
	93 - TOTAL INDIRECT COSTS									
94	TOTAL CONTINGENCY									
94-1	CONTINGENCY ON EQUIPMENT									
94-2	CONTINGENCY ON MATERIAL									
94-3	CONTINGENCY ON LABOR									

TRADE SECRET DATA ENDS]

SARGENT & LUNDY

ESTIMATE NO. : 30919A
PROJECT NO. : 12715.001
ISSUE DATE : 10/29/2010
PREP/REV : RCK / MNO
APPROVED : BJD

[TRADE SECRET DATA BEGINS

OTTER TAIL
BIG STONE STATION
WATER TREATMENT SYSTEM
CONCEPTUAL COST ESTIMATE

PRICE LEVEL: 2010 LOCATION: Sioux Falls, SD WAGE RATE: PRODUCTIVITY FACTOR:

CODE OF ACCOUNT	DESCRIPTION A	DESCRIPTION B	QTY	UM	EQUIPMENT COST	MATERIAL COST	MAN-HOURS	CREW WAGE RATE	LABOR COST	TOTAL COST
94-4	CONTINGENCY ON INDIRECT									
95	TOTAL ESCALATION									
95-1	ESCALATION ON EQUIPMENT									
95-2	ESCALATION ON MATERIAL									
95-3	ESCALATION ON LABOR									
95-4	ESCALATION ON INDIRECT									
96	**TOTAL CONSTRUCTION COST**									
97	INTEREST DURING CONSTRUCTION	BY OTP								
98	**TOTAL PROJECT COST**									**13,086,900**

TRADE SECRET DATA ENDS]

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ATTACHMENT 6

BIG STONE AQCS PROJECT OPERATING AND MAINTENANCE COST CALCULATIONS

ATTACHMENT 6
BIG STONE AQCS PROJECT
OPERATING & MAINTENANCE (O&M) COST CALCULATIONS[1]

Current Big Stone Plant O&M Costs

2010 Big Stone O&M Non-fuel Budget	$13,655,000
2010 Costs Escalated to 2016 at 3%	$16,304,784
2016 O&M Costs (Rounded)	**$16,300,000**

Additional Big Stone Plant O&M Costs with Addition of AQCS Project

The following is a summary of cost developed jointly by Sargent & Lundy, LLC and Otter Tail Power Company (OTP) based on conceptual design assumptions.[2]

[TRADE SECRET DATA BEGINS

Parameter	SCR	DFGD with New Baghouse
Fixed O&M, $M/yr		
Variable O&M, $M/yr		
Total O&M, $M/yr		
Total AQCS O&M, $M/yr		

TRADE SECRET DATA ENDS]

The variable O&M costs are comprised almost entirely of reagent (lime and ammonia) costs. In the conceptual design phase, reagent usage was calculated at permitted conditions and with no reduction in NO_X from operation of the SOFA system.

AQCS Project Adjusted Variable Costs

To obtain a variable cost estimate that will reflect operating conditions after installation of the AQCS Project, OTP has reduced variable costs to match actual operating conditions based on less flow and less NO_X to remove.

[TRADE SECRET DATA BEGINS

Parameter	SCR	DFGD with New Baghouse
Fixed O&M, $M/yr		
Variable O&M, $M/yr		
Total O&M, $M/yr		**TRADE SECRET DATA ENDS]**
Total AQCS O&M, $M/yr	11.0	

[1] Prepared by Mark Rolfes, P.E., Manager, Generation Development, Otter Tail Power Company (Jan. 4, 2011).
[2] *See* Attachment 5 at 6-2.

For the SCR and semi-dry FGD system the largest portion of the O&M cost are attributable to the reagents used for the chemical reactions. Ammonia in the SCR and Lime in the semi-dry FGD. Based on the current conceptual design, the reagents account for approximately 2/3 of the total variable O&M cost. The remainder is for auxiliary power and maintenance materials.

Total Big Stone O&M Costs with AQCS

Big Stone O&M	$16,300,000
AQCS O&M	$11,000,000
Total O&M	**$27,300,000**

O&M Costs for Activated Carbon Injection System (ACI)

The following is a summary of cost developed jointly by Sargent & Lundy and OTP based on conceptual design assumptions.

[TRADE SECRET DATA BEGINS

Parameter	ACI
Fixed O&M, $M/yr	
Variable O&M, $M/yr	
Total O&M, $M/yr	

TRADE SECRET DATA ENDS]

ACI System Adjusted O&M Costs

To obtain a variable cost estimate that will reflect operating conditions after installation of the ACI Project, OTP has reduced and rounded the O&M cost to match actual operating conditions based on less flow.

In particular, OTP has revised the O&M cost estimate for the ACI system to $2.0 million per year.

ATTACHMENT 7

CONTRACT STRATEGY SUMMARY

Sargent & Lundy LLC

Jack M. Daly
Senior Vice President
312-269-6257
312-269-9678
Jack.m.daly@sargentlundy.com

December 14, 2010
Project No. 12715-001
Letter No. BSP-SL-OTP-0016

Otter Tail Power Company
Big Stone Plant

Contract Strategy Summary

Mr. Mark Rolfes
Otter Tail Power Company
215 S. Cascade Street
Fergus Falls, MN 56538-0496

Dear Mr. Rolfes:

Projects as large as the Big Stone AQCS project demand careful consideration of the contract strategy used to execute the project. The strategy that fits this project best is determined by balancing the risk associated with cost, schedule, and performance against the opportunities offered by the current market conditions. While schedule is not a determining factor for this project, cost and reliability need to be considered carefully. The contract strategy chosen for any project has a direct impact on cost: date certain, price certain, single turnkey contract approach is the most expensive and could cost 10% or more ($50,000,000+) than a more selective approach that is configured to leverage the current slow marketplace to the advantage of the Owners.

While most risks can not be eliminated, they can be balanced by the execution strategy to provide the Owner the best project for the least cost within a defined timeframe. Cost control includes both the ultimate life cycle cost of the project as well as cash flow, and the potential for cost over runs, or cost certainty. For the purpose of comparing the various strategies, it is assumed that all strategies will have the appropriate terms and conditions to keep the quality of the installed product and safety during construction the same across all methods.

Exhibit 1 depicts the cyclic nature of the marketplace associated with environmental projects. The graph depicts two cycles occurring since 1999, each approximately 6 years in length and predicts another cycle to occur in the next six years going forward. The historical data is based on Sargent and Lundy's knowledge of the industry along with input from project participants where possible. The forward projections are based on Owner input where available combined with our opinion of which projects would begin over time.

The cyclic nature of the environmental marketplace is a direct result of being driven by a central outside influence: regulatory requirements. Historical costs have varied over time in response to the market place. Considering FGD projects as an example, the midpoint of the range of historical costs tracked in 2007 was \$300/kw and four years later in 2011, the midpoint is approximately \$500/kw. That represents a 67% increase in cost over a four year period. The rate of increase for SCR projects is similar but slightly less. Exhibit 1 indicates that we are currently at the end of one cycle and poised to begin another which means that we are in a buyer's market and that the advantages of that is likely to diminish rapidly based on historical data.

The best way to keep the prices as low as possible is to allow companies to do what they do best in terms of engineering, fabrication and erection and establish their respective scopes of work to minimize or simplify interfaces. It is imperative that the price of construction, which is nearly 50% of the cost of the project, be determined based on a developed design with the appropriate risk/reward driving performance. This is especially critical for environmental projects because they tend to be unique given the unique constraints of the existing sites. This uniqueness makes it very difficult to determine the price of construction with certainty by looking at past similar sized projects. Enough engineering must be completed to identify the project unique challenges and allow the constructor to determine the cost with confidence. This eliminates the need for excessive contingencies.

The spectrum of contract strategies possible are bracketed by two extremes: at one end is a date certain/price certain turnkey project and the other is the more traditional multi contract style where there are numerous suppliers and contractors all managed by the Owner or Owner's Engineer. We do not recommend either approach for this project at this time. The single turnkey style is too costly, would reduce the Owner's ability to use schedule to your advantage early in the project, restricts the Owner's ability to select individual OEMs and contractor combinations, eliminates more cost effective regional contractors who can not stand up to wrap guarantees, restricts the Owner's input during design development, and increases cost by the turnkey supplier's need to add contingency to their bid due to the fact their bid is based on minimal engineering: probably something on the order of 5% of the engineering needed to complete the design. There are differing opinions of what that cost impact is, but there is no argument that the premium is real. We do not believe the current marketplace warrants that kind of expense.

The traditional multi contract approach should not be considered at this time either. While this will deliver the least cost project, the incremental cost savings compared to a simpler version called an island approach, which is a hybrid between turnkey and multi contract, is too small to outweigh the risks associated with the more complicated nature of a traditional multi-contract approach. The multi contract approach is better suited to a more active, or "seller's" marketplace where there is more to be gained by breaking the project down into it's fundamental building blocks.

We believe that the optimal approach to the project is as follows:

- Boiler modifications to be designed and installed by one company
- FGD Island is an engineer and furnish only contract from scrubber inlet to baghouse outlet. This does not include foundation, electrical supply or controls which will all be in the Balance of Plant (BOP) scope.
- SCR catalyst supply includes flue gas modeling,

- The Balance of Plant is designed by one BOP Engineer who is responsible to manage and integrate the BOP suppliers with the FGD and SCR island suppliers
- The entire project (excluding the boiler modifications) will be installed by one Contractor

This configuration provides all the benefits of a turnkey approach, with the exception of when the final price will be known, plus the following:

- Owner can choose the technology suppliers separate from the contractor
- Owner can participate in the design development without excessive cost impact
- Owner has much more schedule flexibility to react to market changes or regulatory issues.
- Cost is kept to a minimum by giving the Contractor a developed design to bid from. There will be no need for the Contractor to include higher contingencies to account for unknowns and the contract can be configured to incentivize performance and share risk rather than shed risk.
- More competitive bidding by structuring the contract so experienced/competent regional contractors can bid. Due to the size of this project, only large national contractors have the risk tolerance to bid a single turnkey project.

We believe that the nature of this project and the current market conditions clearly support the hybrid contract approach described above. With the appropriate schedule management and timely decision making, this approach will out perform all other variations in terms of risk management and overall project cost. This simple hybrid variation will allow the Owner to take full advantage of what the industry currently has to offer.

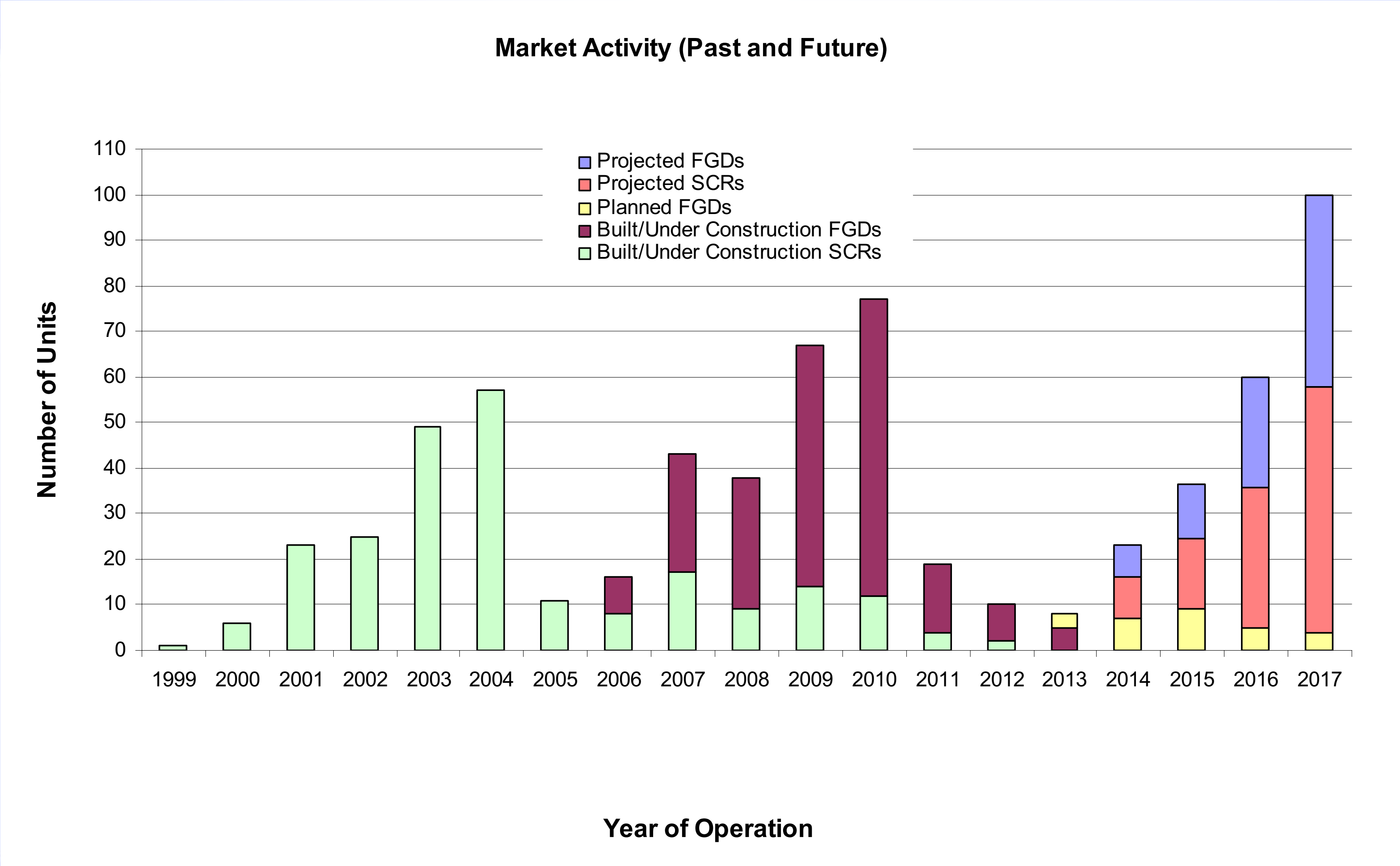
Yours very truly,

JM Daly

Jack M. Daly
Project Director

JMD:cl
Enclosure -- All Recipients
Copies:
K. A. Mixer
File Nos. 2.03 \ 1.16
BSP-SL-OTP-0016.doc

Exhibit 1
FGD and SCR Market Activity



Sargent & Lundy LLC

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ATTACHMENT 8

NATURAL GAS CONVERSION CONCEPTUAL STUDY

Sargent & Lundy LLC

Kenneth A. Mixer
Project Manager
312-269-2235
kenneth.mixer@sargentlundy.com

December 2, 2010
Project No. 12715-002
Letter No. BSP-SL-OTP-0015

Otter Tail Power Company
Big Stone Plant

SL-010476 Final Report
Natural Gas Conversion Conceptual Study

Mr. Mark Rolfes
Otter Tail Power Company
215 S. Cascade Street
Fergus Falls, MN 56538-0496

Dear Mr. Rolfes:

Enclosed is the latest Natural Gas Conversion Conceptual Study with everyone's comments incorporated

Please do not hesitate contacting me if you have any additional questions.

Yours very truly,

Ken A. Mixer
Project Manager

Ken A. Mixer
Project Manager

KAM:km
Enclosure – All Recipients
File No. 2.03
BSP-SL-OTP-0015.doc

OTTER TAIL POWER COMPANY

BIG STONE UNIT 1

NATURAL GAS CONVERSION CONCEPTUAL STUDY

SL-010476
Final Report

December 2, 2010
Project 12715-002

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

LEGAL NOTICE

This Deliverable was prepared by Sargent & Lundy, L.L.C. (S&L) expressly for the sole use of Otter Tail Power Company (Client) in accordance with the agreement between S&L and Client. This Deliverable was prepared using the degree of skill and care ordinarily exercised by engineers practicing under similar circumstances. Client acknowledges: (1) S&L prepared this Deliverable subject to the particular scope limitations, budgetary and time constraints, and business objectives of the Client; (2) information and data provided by others may not have been independently verified by S&L; and (3) information and data contained in this Deliverable are time-sensitive and changes in the data, applicable codes, standards, and acceptable engineering practices may invalidate the findings of this Deliverable. Any use or reliance upon this Deliverable by third parties shall be at their sole risk.

CONTRIBUTORS AND CERTIFICATION

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K. J. Snell

W. A. Patel

REVIEWED BY:

W. C. Stenzel

APPROVED BY:

K. Mixer

12-02-2010
Date

CERTIFICATION

I certify that this Report was prepared by me or under my direct supervision and that I am a registered Professional Engineer under the laws of the State of South Dakota.

K. Mixer
Project Manager

12-2-2010
Date

REGISTERED PROFESSIONAL ENGINEER
REG. NO. 10344
KENNETH A. MIXER
SOUTH DAKOTA

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Table/Figure **Page**

TABLES [TRADE SECRET DATA BEGINS

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FIGURES

EXECUTIVE SUMMARY

Otter Tail Power (OTP) authorized Sargent & Lundy, L.L.C (S&L) to perform a preliminary, high-level study to evaluate the conversion of Big Stone Unit 1 from firing coal to firing natural gas. The results of the study as presented in this report provide OTP with estimated natural gas firing boiler performance data and conversion costs to compare against continued coal firing with new selective catalytic reduction (SCR) and flue gas desulfurization (FGD) systems.

This report provides a high-level/preliminary development of scope, design, performance and cost information, including the following:

- Overview of applicable permitting issues and flue gas emissions requirements.
- Conceptual review of converting the boiler to fire natural gas.
  - Cyclone modifications for natural gas firing.
  - Cyclone flue gas recirculation (CFGR) introduced in the windbox for reduced NO_X emissions
  - Boiler pressure part-assumed modifications.
  - Boiler performance, including boiler efficiency and unit output.
- Installation of an in-duct SCR.
- Estimated 100% unit output emission rates.

[TRADE SECRET DATA BEGINS

- Capital cost estimate that is based on an order-of magnitude level of accuracy of , which is usually an acceptable range for the evaluation of coal versus natural gas because the fuel costs over the forecasted future years of operations are the dominant cost impact. TRADE SECRET DATA ENDS]
- Estimated capital cost and estimated operations and maintenance (O&M) reductions.

PERMITTING IMPACTS

Converting an existing electric utility steam generating unit from coal to natural gas firing subjects the unit to a number of environmental regulations, including the New Source Performance Standards (NSPS), New Source Review (NSR) preconstruction review regulations, and South Dakota air quality emission standards. The environmental regulatory review determined the following:

- The maximum hourly emissions of NO_X, SO_2, or PM are not likely to increase, which would trigger applicability of the most recent Subpart Da NSPS requirements.
- Annual emissions of NSR-regulated pollutants NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHGs would be expected to decrease. CO and VOC emission changes will be a function of the baseline and post-conversion emission rates, heat inputs, and capacity factors.
- If PSD is triggered for CO and/or VOC emissions, BACT would require combustion controls designed to minimize CO/VOC formation, and could require post-combustion catalytic oxidation control.
- Converting Big Stone Unit 1 to natural gas would significantly reduce annual SO_2 emissions.
- Modeled visibility impacts on Class I Areas should be below the 0.5-dv threshold.

DESIGN AND OPERATING IMPACTS

The Big Stone Unit 1 cyclone boiler was originally designed for North Dakota lignite coal but was switched to burn PRB coal in 1995. OTP advised that the boiler is generally operating in its original design condition and the unit continues to use furnace flue gas recirculation (FFGR) for steam temperature control.

[TRADE SECRET DATA BEGINS

Modifying the existing cyclones for natural gas firing, installing a separated overfire air (SOFA) system, and using the existing FFGR system to achieve full unit output should achieve NO_X emissions of and CO levels below boiler output. Installing CFGR system should result in NO_X emissions below and CO levels below , while achieving full unit output. An SCR system is required to arrive at NO_X emissions of , which may be required by the South Dakota Regional Haze regulations.

Boilers of this vintage often were designed with minimum furnace flue gas negative (implosion) system pressure transient capability. Big Stone Unit 1 was designed for +3/-7 in.H_2O. The National Fire Protection Association (NFPA) code, which determines this design parameter, currently requires WG for new units. Furnace reinforcement (mainly buckstay modifications) will be needed because there is the potential for greater negative furnace flue gas pressure excursions when the boiler is tripped with natural gas. A separate study conducted by S&L for OTP[1] recommended to reinforce the furnace to at least WG, based on evaluations and studies of other

TRADE SECRET DATA ENDS]

[1] SO_2, NO_X, and Mercury Reduction Study, *Conceptual Engineering Study Report*, Draft SL-010408, September 24, 2010.

[TRADE SECRET DATA BEGINS

similar boilers, and input from . Preliminarily, S&L has assumed that a minimum of WG will be required for natural gas firing. Boiler reinforcement to WG is included in the capital cost estimate.

TRADE SECRET DATA ENDS]

The existing boiler equipment associated with coal and the coal yard equipment would be retired in place. Sootblowers, coal feeders, ash handling, pulverizers, and other coal equipment would also be retired in place. It is expected that the existing wet bottom ash hopper will be reused for the unit conversion. The water seal between the furnace and bottom ash hoppers is assumed to allow air flow into the furnace during a natural gas fuel trip and reduce the negative furnace pressure transient.

With vintage boilers, water wall, superheater (SH), and/or reheater (RH) tube material and condition repairs and replacements are typically normal plant maintenance activities. OTP should perform a condition assessment on all major pressure parts to determine the existing condition of this equipment. This study does not consider the scope or costs for the replacement of the SH, RH, or economizer (convection pass) surfaces due to metallurgical deterioration, erosion, or other typical operational issues.

Converting a coal-fired boiler to 100% natural gas firing eliminates slagging/fouling of the convection-pass tube assemblies, which results in increased heat transfer and tube temperatures. Therefore, convection-pass tubing upgrades/modifications, either material upgrades and/or surface additions, are often needed to achieve 100% unit output when firing 100% natural gas. However, the modifications necessary would be dependent on the boiler arrangement and require computer modeling to determine. Based on this preliminary, high-level study, the costs for boiler computer modeling and convection-pass pressure part modifications are included in the cost estimate.

Cycling operation is often required when firing natural gas because of higher fuel costs. Cycling operation requires major modifications to the boiler, turbine and other areas, as well as the addition of a turbine bypass system. This is included in the capital cost estimate.

[TRADE SECRET DATA BEGINS

The conceptual capital cost to convert Big Stone Unit 1 to 100% natural gas includes new burners and boiler modifications associated with the conversion itself as well as an in-line SCR system to achieve outlet emissions of $\leq$0.10 lbs NO_X/mmBtu and 100% unit output. The natural gas conversion capital costs are estimated to be $ as summarized in Table 4-1 of the study and the conversion is expected to require approximately from start of work to commercial operation, with an outage duration of approximately , which includes burner and pressure part modifications. TRADE SECRET DATA ENDS]

1. INTRODUCTION

1.1 GENERAL

Otter Tail Power (OTP) authorized Sargent & Lundy, L.L.C (S&L) to perform a preliminary, high-level study to evaluate the conversion of Big Stone Unit 1 from firing coal to firing natural gas. The results of the study as presented in this report provide OTP with estimated natural gas firing boiler performance data and conversion costs to compare against continued coal firing with new selective catalytic reduction (SCR) and flue gas desulfurization (FGD) systems.

[TRADE SECRET DATA BEGINS

The unit is rated at 475 MW net (495 MW gross) and the boiler is a balanced-draft, cyclone-fired steam generator. In 1995, the unit was converted from firing lignite to Powder River Basin (PRB) coal. . In 1996, the lignite predry system was removed, partially to reduce maintenance on this system, but also to allow for a simple separated overfire air (SOFA) system that was installed in the same boiler penetration as the original predry vent lines. The system takes secondary air from the top of the windbox and delivers it through the gas recirculation plenum to four ports on the front and back furnace walls (eight ports total). Each SOFA duct has an air damper controlled by the distributed control system (DCS). NO_X currently is controlled to about 0.70-0.80 lbs/mmBtu across the load range. Boiler excess O_2 (as measured at the economizer outlet – wet basis) is controlled to 2.5% at loads between 300-500 MW. The permitted boiler heat input is 5,609 mmBtu/hr.

The unit was originally designed with an electrostatic precipitator (ESP). In 2001, the ESP was converted to an system, whereby it functioned both as an ESP and fabric filter for particulate control. Removing the fabric filters should compensate the change in pressure through the SCR.

TRADE SECRET DATA ENDS]

This report provides a preliminary, high-level development of scope, performance, and cost information, covering:

- Overview of applicable permitting issues and flue gas emissions requirements.
- Conceptual review of converting the boiler to fire natural gas.
  - — Cyclone modifications for natural gas firing.
  - — Cyclone flue gas recirculation (CFGR) introduced in the windbox for reduced NO_X emissions
  - — Boiler pressure part-assumed modifications.
  - — Boiler performance, including boiler efficiency and unit output.
- Installation of an in-duct SCR.
- Estimated 100% unit output emission rates. [TRADE SECRET DATA BEGINS
- Capital cost estimate that is based on an order-of magnitude level of accuracy of , which is usually an acceptable range for the evaluation of coal versus natural gas because the fuel costs over the forecasted future years of operations are the dominant cost impact. TRADE SECRET DATA ENDS]
- Estimated capital cost and estimated operations and maintenance (O&M) reductions.

The boiler has a furnace flue gas recirculation (FFGR) system to control main steam and reheat temperatures. Currently, the boiler operates using only one of the two gas recirculation fans.

1.2 STUDY BASIS

S&L used information such as design plant reference drawings and data from prior projects and studies, as well as from industry references in preparing this study. This information obtained was sufficient to conduct this preliminary, high-level development study.

Boiler and other suppliers were not contacted for specific information. S&L prepared preliminary calculations only to estimate boiler natural gas consumption, unit output, steam temperatures, air and flue gas flows, and emissions at 100% boiler output.

1.3 TECHNOLOGY DISCUSSION

The following describes major systems needed for natural gas firing.

1.3.1 Fuel Conversion to Natural Gas [TRADE SECRET DATA BEGINS

CFGR reduces NO_X formation by recycling a portion of the flue gas back into the primary combustion zone. The recycled flue gas lowers NO_X emissions by two mechanisms. First, the recycled gas, consisting of products that are inert during combustion, lowers the combustion temperatures and second the O_2 content in the primary flame zone is reduced. The amount of recirculation is limited based on flame stability. CFGR is effective on natural gas-fired boilers because it reduces the formation of thermal NO_X, which represents almost 100% of the NO_X produced in a natural gas-fired boiler. NO_X emissions below and CO levels below are expected with the use of new natural gas burners, SOFA, and CFGR fans. TRADE SECRET DATA ENDS]

1.3.2 Selective Catalytic Reduction

SCR is a process in which ammonia reacts with NO_X in the presence of a catalyst to reduce the NO_X to nitrogen and water. The catalyst enhances the reactions between NO_X and ammonia, according to the following reactions:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

$$4\ NO_2 + 8\ NH_3 + 2\ O_2 \rightarrow 6\ N_2 + 12\ H_2O$$

The location for this process in a typical boiler is downstream of the economizer and upstream of the air heater. SCR technology can be applied at a "full-scale," which is an independent reactor vessel with inlet and outlet ducting or "in-line," whereby the SCR uses the current ductwork, modified as required to expand the dimensions of the flue to hold the catalyst.

In-line SCR systems differ from full-scale SCR systems because they are installed within the existing flue gas flow path, as opposed to a separate reactor structure. Such SCR systems are usually installed in cases where only 40-60% reduction is required for coal-fired units and greater than 90% reduction is required for gas-fired units. Installation requires "ballooning" the ductwork to reduce the normal 60 fps flue gas velocities to the required 20-25 fps range. Thus, physical space must be available around the existing ductwork to accommodate the larger duct dimensions.

[TRADE SECRET DATA BEGINS

Static mixers are typically installed upstream of the ammonia injection grid to provide uniform temperature distribution throughout. For gas units, due to space constraints, static mixers are not typically installed as high ammonia slip ( ) can be tolerated. The ammonia grid can be used to distribute ammonia more closely using nozzles close to each other.

Exposure of the catalyst to either liquid water or high humidity environments should be avoided. Equipment should be oriented such that accidental leaks, water washing, operations, and so forth, do not subject the catalyst to direct water exposure. Electric heaters in a recirculation loop are used to continually remove, heat, and return the gas/air maintained in the reactor.

NO_X emissions resulting from the conversion of the unit to natural gas, FFGR, and SOFA are expected to range from . At this inlet NO_X concentration, the SCR would be expected to achieve a controlled outlet NO_X emission rate of . TRADE SECRET DATA ENDS]

2. PERMITTING

Converting an existing electric utility steam generating unit from firing coal to natural gas may subject the unit to a number of environmental regulations, including the New Source Performance Standards (NSPS), New Source Review (NSR) preconstruction review regulations, and South Dakota air quality emission standards. Typically, NSR regulations dictate the emission limits and control technologies required for modifications to an existing major source of emissions; however, in the case of Big Stone Unit 1, the South Dakota Regional Haze regulations may require more stringent NO_X emission limits. This section of the report reviews the environmental regulations and emission limits that may apply to the natural gas conversion project.

2.1 GENERAL

The South Dakota Department of Environment and Natural Resources (SDENR) issued a Title V Operating Permit for the Big Stone Generating Station on June 9, 2009 (Permit #28.0801-29). The operating permit sets emission limits applicable to existing emission sources at the facility. The emission limits applicable to Big Stone Unit 1 are summarized in Table 2-1.

Table 2-1. Emission Limits

Operating Parameter or Pollutant	Emission Limit
Descriptive operating rate	5,609 mmBtu/hr
Total suspended particulate matter	0.3 lbs/mmBtu
SO_2	3.0 lbs/mmBtu
PM_{10} (filterable)	0.26 lbs/mmBtu

2.2 NEW SOURCE PERFORMANCE STANDARDS

NSPS regulations implement Section 111(b) of the Clean Air Act (CAA) and are issued for categories of sources that may cause or contribute to air pollution. The U.S. Environmental Protection Agency (EPA) has published NSPS emission standards for several industrial source categories, including Electric Utility Steam Generating Units (EUSGUs) (i.e., utility boilers) capable of combusting more than 250 mmBtu/hr heat input of fossil fuel, for which construction, modification, or reconstruction commenced after September 18, 1978. The EUSGU NSPS is published in 40 CFR Part 60 Subpart Da. South Dakota has incorporated the Subpart Da NSPS into its air pollution control program regulations (ARSD 74:36:07:03).

Under the NSPS regulations, a "modification" is defined as "any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies" to be expressed in terms of hourly mass emissions (40 CFR 60.14). Additional clarification for determining whether a change to an existing EUSGU meets the definition of a "modification" is provided in 40 CFR 60.40 Da(h):

> No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the <u>maximum hourly emissions</u> of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

Big Stone Unit 1 meets the definition of a Subpart Da EUSGU (i.e., it is an EUSGU with a heat input capacity greater than 250 mmBtu/hr). Thus, if the natural gas conversion project meets the definition of modification, Big Stone Unit 1 would become subject to the most recent Subpart Da NSPS emission standards. Upon modification, an existing facility becomes an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere (§60.14(a)). Subpart Da includes emission standards for nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM), but does not include emission standards for carbon monoxide (CO), volatile organic compounds (VOC), or any other air pollutants.

Potential emission changes associated with the conversion project must be evaluated to determine whether the project would result in increased maximum pounds per hour emissions of NO_X, SO_2, or PM. Post-conversion maximum hourly emissions are a function of: (1) the maximum full-load natural gas heat input to the boiler (mmBtu/hr); and (2) the pollutants' maximum controlled emission rate (lb/mmBtu).

As part of this natural gas conversion study, S&L prepared preliminary boiler and unit performance calculations for the natural gas-fired case, taking into consideration boiler efficiency and auxiliary power requirements. In general, converting a coal-fired boiler to fire natural gas will slightly decrease boiler efficiency; however, auxiliary power requirements are significantly less for the natural gas-fired case because there are no solid fuel or ash handling systems. The net turbine heat rate stated in the previously noted S&L report was used in the estimated performance calculations. The Big Stone Unit 1 estimated performance calculations for the natural gas-fired case are summarized in Table 2-2.

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Table 2-2. Natural Gas Firing Performance Summary

Parameter	Performance
Gross plant output (kW)	
Auxiliary power (kW)	
Boiler efficiency (%)	
Net plant output (kW)	
Net plant heat rate (Btu/kWh-net)	
Full-load heat input (mmBtu/hr)	
Full-load NG fuel feed rate, (lb/hr)	

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Based on S&L's preliminary boiler performance calculations, it can be concluded that the natural gas conversion will not result in an increased maximum full-load heat input to the boiler, and that the maximum hourly heat input to the boiler will remain below the current descriptive operating limit in the facility's operating permit of 5,609 mmBtu/hr.

Natural gas is a low-sulfur and low-ash fuel. Emissions of SO_2 from natural gas-fired boilers are negligible because pipeline quality natural gas typically has sulfur levels of 2,000 grains per million cubic feet, which equates to a maximum SO_2 emission rate of approximately 5.9×10^{-4} lbs/mmBtu, assuming 100% conversion of fuel sulfur to SO_2. Because natural gas is a gaseous fuel, filterable PM emissions are also low. PM emissions from natural gas combustion are usually larger molecular weight hydrocarbons that are not fully combusted, and increased PM emission may result from poor air/fuel mixing. The AP-42 emission factor for total PM (filterable + condensable) emissions from a natural gas-fired boiler is 7.5×10^{-3} lbs/mmBtu (AP-42 Table 1.4-2).

The principal mechanism of NO_X formation in natural gas combustion is thermal NO_X. Thermal NO_X formation occurs through the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most of the thermal NO_X formation occurs in the high-temperature flame zone near the burners, and can be affected by oxygen concentration, peak temperature, and residence time at peak temperature. NO_X emission levels can vary considerably with the type and size of the combustor and with operating conditions, including combustion air temperature, volumetric heat release rate, load, and excess oxygen level (see, AP-42, page 1.4-2). Based on an engineering evaluation of the existing cyclone-fired boiler (see Section 3 of this report), and taking into consideration NO_X emission rates currently achieved in practice, it is expected that the existing boiler

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would achieve NO_X emissions of approximately using combustion controls such as new natural gas burners only. Boiler NO_X emissions could be reduced to approximately and achieve full unit output with continued use of the FFGR system. Post-combustion SCR could be used to further reduce NO_X emissions to a rate of approximately .

Expected natural gas NO_X (with and without SCR), SO_2, and PM emission rates, and the corresponding full-load pounds per hour emissions, are summarized in Table 2-3.

Table 2-3. Projected Natural Gas Firing Emissions Summary

Pollutant	Controlled Emission Rate (lb/mmBtu)	Maximum Hourly Emission Rate (lb/hr)
NO_X (LNB / SOFA / FFGR)		
NO_X (LNB / SOFA / FFGR or CFGR + SCR)		
SO_2		
PM		

Hourly emission rates listed in Table 2-3 are based on a maximum full-load heat input of to the boiler, and can be compared with the existing maximum hourly emission rates to determine NSPS applicability. Typically, based on predicted emissions from previous S&L studies and experience, natural gas conversion projects do not trigger NSPS applicability. Due to uncertainty in the industry with converting a cyclone boiler to 100% natural gas firing, NSPS may be triggered and the modified boiler would have to meet the applicable NSPS emission limits. For any affected facility for which modification commenced after February 28, 2008, NO_X emissions must not exceed 1.4 lbs/MWh gross energy output or 0.15 lbs/mmBtu based on a 30-day rolling average (§60.45Da(e)(3)). TRADE SECRET DATA ENDS]

2.3 NEW SOURCE REVIEW

NSR is a preconstruction review and permitting program that applies to major new sources of air pollution and "major modifications" of an existing major source of air pollution. Specific NSR standards depend upon the location of the emission source. Sources located in an area meeting the National Ambient Air Quality Standards (NAAQS) are subject to the Prevention of Significant Deterioration (PSD) regulations in ARSD 74:36:09 (incorporating the federal regulations in 40 CFR 52.21), while sources located in areas that do not meet the NAAQS are subject to the nonattainment area regulations in ARSD 74:36:10.

Big Stone Unit 1 is located in Grant County in the northeast corner of South Dakota. Grant County, and all adjacent counties, has been designated as attainment or unclassifiable for all NAAQS, including the eight-hour ozone and $PM_{2.5}$ standards. Therefore, modifications to Big Stone Unit 1 that result in a significant net increase in annual emissions of an NSR-regulated pollutant would be subject to the PSD regulations in ARSD 74:36:09.

2.3.1 NSR Exclusions

Two NSR exclusions may apply to natural gas conversion projects. First, modifications to an existing facility are excluded from NSR review if they fall under the routine maintenance, repair and replacement (RMRR) exclusion. Historically, EPA applied the RMRR exclusion on a case-by-case basis using a multi-factor test for determining whether a particular activity falls within the exclusion. Based on a review of RMRR decisions and EPA guidance, it is unlikely that the natural gas conversion project would fall under the RMRR exclusion.

Second, the regulations exempt from NSR review the use of an alternative fuel by a stationary source if the source was capable of accommodating the fuel before January 6, 1975, provided the source was not prohibited from burning the fuel by a federally enforceable permit condition. To be subject to this exclusion, EPA generally takes the position that the source must have been designed and constructed to accommodate the fuel prior to January 6, 1975, and that the source must have been continuously capable of accommodating the alternative fuel since before January 6, 1975. Because Big Stone Unit 1 was not designed to fire natural gas, and has not been continuously capable of accommodating natural gas, it is unlikely that the natural gas conversion project would be subject to this exclusion.

Thus, the project will be subject to NSR review due to industry uncertainty regarding converting cyclone units to 100% natural gas firing.

2.3.2 PSD Applicability

The PSD permitting requirements apply to any project that is considered a "major modification" at a facility that is an existing major stationary source of emissions located in an attainment area. (40 CFR 52.21(a)(2)). A project will not be a "major modification" for any federally regulated new source review pollutant if either of the following occurs:

- (1) emissions associated with the project (the "project emissions increase") are less than the PSD significant rates identified in 40 CFR 52.21(b)(23), or
- (2) the net change in emissions from the source, including all emission units at the facility, are below the PSD significant emission rate.

The significant PSD emission rates are listed in Table 2-4.

Table 2-4. PSD Significant Emission Rates (40 CFR 52.21(b)(23))*

Pollutant	PSD Significant Emission Rate (ton/yr)
Carbon monoxide (CO)	100
Nitrogen oxides (NO_X)	40
Sulfur dioxide (SO_2)	40
Particulate matter (PM)	25
Particulate matter < 10 μm (PM_{10})	15
Particulate matter < 2.5 μm ($PM_{2.5}$)	10
Ozone	40 - VOC or NO_X
Sulfuric acid mist (H_2SO_4)	7
Fluorides	3
Lead	0.6

*The definition of "significant" in 40 CFR 52.21(b)(23) includes emission levels for other air pollutants; however, emissions of the other air pollutants (including reduced sulfur compounds and hydrogen sulfide) will be insignificant from coal-fired steam electric generating units.

2.3.3 PSD Emissions Netting

The procedure for calculating whether a significant emissions increase will occur depends upon the type of emissions units being modified. Different procedures are used for projects that involve only existing emissions units and projects that involve both existing and new units. For projects involving only an existing unit, a significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions and the baseline actual emissions from the unit equals or exceeds the significant amount for that pollutant (see, 40 CFR 52.21(a)(2)(iv)(c)).

For any existing EUSGU, "baseline actual emissions" means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within a five-year period immediately preceding when the owner or operator begins actual construction of the project, excluding any non-compliant emissions (see, 40 CFR 52.21(b)(48)(i)). Projected actual emissions means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the five years (12-month period) following the date the unit resumes regular operation (40 CFR 52.21(b)(41)(i)). In determining the projected actual emissions, the owner/operator should exclude that portion of the unit's emissions following the project that the existing unit could have accommodated during the baseline period that are unrelated to the project, including any increased utilization due to product demand growth (40 CFR 52.21(b)(41)(ii)(c)).

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Table 2-5 provides natural gas combustion emission rates that can be used to calculate post-conversion emissions. NO_X emission rates included in the table are provided for the combustion control option (low-NO_X burner [LNB]) and the SCR option. Post-conversion annual emissions can be calculated using the emission factors in Table 2-5, a full-load heat input of , and a projected capacity factor.

Table 2-5. Natural Gas-Fired Boiler Emission Rates

	Natural Gas Emissions (lb/mmBtu)		
Pollutant	**LNB / SOFA / FFGR**	**LNB / OFA / FFGR or CFGR + SCR**	**Basis**
NO_X			Performance calculations and engineering judgment.
CO			Performance calculations and engineering judgment.
SO_2	5.9×10^{-4}	5.9×10^{-4}	AP-42 Table 1.4-2 (0.6 lbs/10^6 scf)
PM (total)	7.5×10^{-3}	7.5×10^{-3}	AP-42 Table 1.4-2 (7.6 lbs/10^6 scf)
PM_{10} (filterable)	1.9×10^{-3}	1.9×10^{-3}	AP-42 Table 1.4-2 (1.9 lbs/10^6 scf)
$PM_{2.5}$ (total)	5.6×10^{-3}	5.6×10^{-3}	AP-42 Table 1.4-2 (5.7 lbs/10^6 scf)
VOC	5.4×10^{-3}	5.4×10^{-3}	AP-42 Table 1.4-2 (5.5 lbs/10^6 scf)
H_2SO_4			Calculated based on SO_2 emission rate and assuming SO_2-to-SO_3 conversion in boiler.
CO_2	117.6	117.6	AP-42 Table 1.4-2 (120,000 lbs/10^6 scf)

*NO_X and CO emission factors were estimated based on an engineering evaluation of the emission rates achievable firing natural gas in Big Stone Unit 1. NO_X emission rates are provided for the combustion control option (LNB) and the SCR option. A controlled NO_X emission rate of is equivalent to a NO_X concentration of approximately . A controlled CO emission rate of is equivalent to a CO concentration of approximately . Other emission factors were based on the AP-42 factors for large natural gas-fired boilers. AP-42 emission factors were converted to lbs/mmBtu using a value of 1,020 Btu/scf for natural gas. Sulfuric acid mist emissions were calculated assuming SO_2-to-SO_3 conversion in the boiler.

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Net emission changes associated with the natural gas conversion project can be calculated by comparing baseline existing actual emissions from the boiler to the projected annual emissions using the boiler performance and emission factors in Table 2-2 and Table 2-5, respectively.

Based on netting calculations prepared for similar projects, natural gas conversions typically do not trigger PSD review for any NSR-regulated pollutant, except potentially CO and VOC. Because natural gas is an inherently low-sulfur and low-ash fuel, annual emissions of SO_2, PM, PM_{10}, $PM_{2.5}$, and H_2SO_4 will likely be reduced significantly, even assuming a 100% post-conversion capacity factor. Annual NO_X emissions are a function of the controlled NO_X emission rate; however, even without post-combustion NO_X control, annual NO_X emissions would be expected to decrease. CO and VOC emission changes will be a function of the baseline and post-conversion emission rates, heat inputs, and capacity factors used in the netting calculation.

Due to industry uncertainty regarding converting a cyclone boiler to 100% natural gas firing, the project might be subject to the PSD pre-construction review and permitting regulations. PSD permitting requires, among other things, a Best Available Control Technology (BACT) analysis, installation of BACT controls, and air quality impact modeling. BACT for CO/VOC control from a large natural gas-fired boiler would likely require combustion controls designed to minimize CO/VOC formation, and could potentially require a post-combustion catalytic oxidation control system.

2.3.4 Greenhouse Gas Emissions under PSD

Greenhouse gas (GHG) emissions, including carbon dioxide (CO_2), are not currently regulated as NSR-regulated pollutants. However, on May 13, 2010, EPA released a final rule intended to clarify how CAA permitting requirements, including the PSD program, will be applied to GHG emissions from power plants and other stationary facilities. The rule is commonly known as the "Tailoring Rule" because it adjusts the PSD threshold requirements applicable to other NSR-regulated pollutants to make them appropriate for GHG emissions.

The Tailoring Rule establishes two initial steps for phasing in regulation of GHGs under the PSD permitting program for modifications to existing facilities:

- **Step 1 (January 2, 2011, through June 30, 2011)**. GHGs must be addressed in PSD pre-construction permits for new or modified facilities that require a PSD permit based on their emissions of other regulated pollutants (sulfur dioxide, particulate matter, etc.) and that increase net GHG emissions by at least 75,000 tons per year CO_2-equivalent (CO_2e).
- **Step 2 (July 1, 2011, through June 30, 2013)**. GHGs must be addressed in PSD pre-construction permits for modifications of existing facilities that increase net GHG emissions by at least 75,000 tons per year CO_2e, even if they would not require a PSD permit based on their emissions of other regulated pollutants.

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Potential post-conversion annual CO_2 emissions can be calculated using the information in Table 2-2 and Table 2-5. Because of the lower carbon content of natural gas (compared with coal), CO_2 emissions associated with natural gas combustion are approximately of the CO_2 emissions associated with coal combustion. The AP-42 emission factor for CO_2 emissions from natural gas-fired boilers is , compared with typical coal-fired CO_2 emission factors in the range of . Thus, assuming no significant increase in the annual heat input to the boiler, natural gas conversion projects result in less CO_2 and GHG emissions, and will not trigger NSR review of GHGs. TRADE SECRET DATA ENDS]

2.4 SOUTH DAKOTA REGIONAL HAZE PROGRAM

South Dakota published its Draft Regional Haze State Implementation Plan (SIP) in August 2010. The proposed regional haze regulations are included in the Administrative Rules of South Dakota (ARSD) Article 75:36. Regional haze regulations are designed to limit emissions from existing stationary sources that may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Class I Area. SDENR defined "contribute" to visibility impairment as a change in visibility impairment in a mandatory Class I Area of 0.5 deciviews (dv) or more, based on a 24-hour average, above the average natural visibility baseline. The rule applies to Best Available Retrofit Technology (BART)-eligible sources, and requires existing sources to control NO_X, SO_2, and PM emissions using BART.

Baseline visibility impact modeling conducted by SDENR and OTP concluded that Big Stone Unit 1 was a BART-eligible source. Based on these results, SDENR requested that OTP complete a case-by-base BART analysis, which includes evaluating the technical feasibility of potentially available retrofit control technologies, conducting an economic impact analysis, and determining the visibility improvement expected at the Class I Areas. Based on the Big Stone Unit 1 BART determination, SDENR proposed the BART emission limits summarized in Table 2-6. A comparison of the pounds per hour BART emission limits and the projected maximum hourly emissions after conversion to natural gas is provided in Table 2-7.

Table 2-6. Proposed Big Stone Unit 1 BART Emission Limits

	Proposed BART Emission Limits	
Pollutant	lb/mmBtu	lb/hr
NO_X	0.10	561
SO_2	0.09	505
PM	0.012	67.3

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Table 2-7. Comparison of the BART Emission Limits and Projected Natural Gas Emission Rates

Pollutant	Proposed BART Emission Limit (lb/hr)	Natural Gas – Maximum Hourly Emission Rate (lb/hr)
NO_X	561	
SO_2	505	
PM	67.3	

The BART emission limits summarized in Table 2-6 were determined by SDENR to reflect emission reductions that should be achievable at Big Stone Unit 1 using BART, taking into consideration costs and visibility impairment. Modeled visibility impacts from Big Stone Unit 1 at these emission rates were well below the 0.5-dv "contribute" threshold at all Class I Areas (see South Dakota Regional Haze SIP, draft, page 95). In fact, modeled impacts were below the 0.5-dv threshold for control options with higher emissions. For example, Option #6 (SNCR, SOFA, and DFGD #1) did not exceed the 0.5-dv thresholds with controlled emissions of: 841.4 lbs/hr SO_2; 1,963.2 lbs/hr NO_X; and 84.1 lbs/hr PM.

Hourly SO_2 emissions after conversion to natural gas would be less than of the proposed BART emission limit for Big Stone Unit 1, and PM emissions would be approximately below the corresponding BART limit. Based on visibility impact modeling included in the Regional Haze SIP, it appears that impacts from Big Stone Unit 1 (firing natural gas) would be below the 0.5-dv threshold, even at a NO_X emission rate of . Impact modeling would be needed to quantify visibility impairment at the various NO_X emission levels, and to compare the modeled impacts to those in the Regional Haze SIP. Although modeling may show that Big Stone Unit 1 does not contribute to visibility impairment at any Class 1 Areas, even at the higher NO_X emission rates, this study assumed

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that post-conversion NO_X emissions would need to be controlled to an emission rate of , or less (the proposed Big Stone Unit 1 BART limit). Based on a full-load heat input of 4,844 mmBtu/hr, this equates to a controlled NO_X emission rate of . As discussed in Section 3 of this report, it is likely that post-combustion SCR would be needed to achieve an emission rate of , or less, on the natural gas-fired boiler. TRADE SECRET DATA ENDS]

2.5 ACID RAIN PROGRAM REQUIREMENTS

Big Stone Unit 1 is an affected unit under the federal Acid Rain Program (ARP), and currently receives SO_2 allowances pursuant to the CAA Title IV. Based on a review of allowance allocation data available on EPA's Clean Air Markets Web site, Big Stone Unit 1 currently receives approximately 12,973 SO_2 allowances annually. Table 2-8 compares the projected SO_2 annual emissions (assuming a 100% capacity factor) to the facility's annual SO_2 allowances.

Table 2-8. Projected SO_2 Emissions vs. Acid Rain Program Allowances

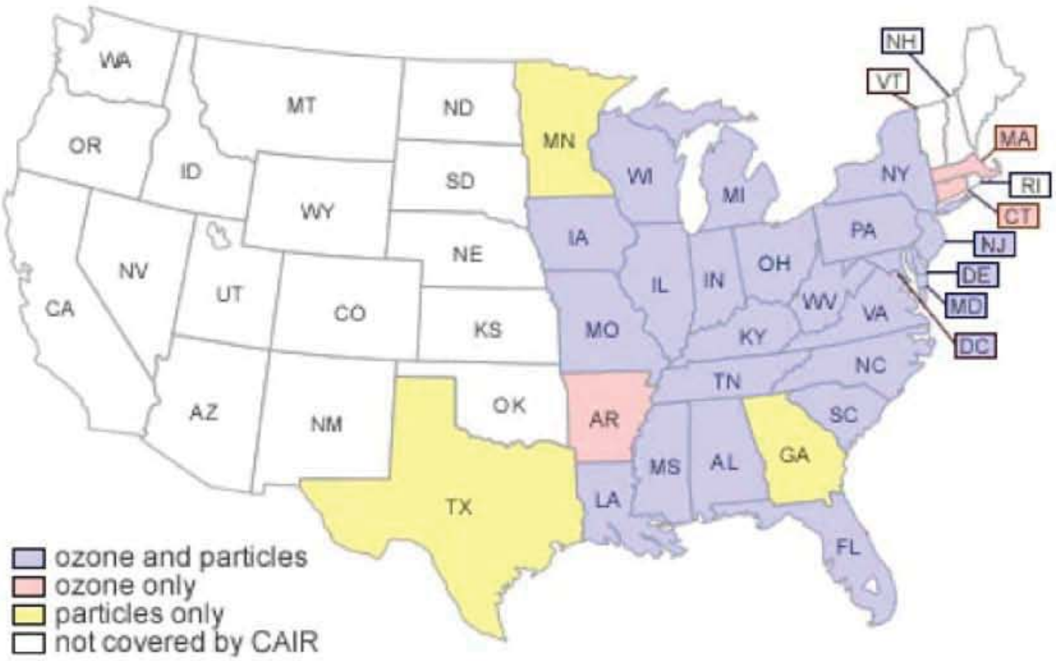
	Projected Annual SO_2 Emissions (tpy)	ARP Annual SO_2 Allowances (tpy)	
[TRADE SECRET DATA BEGINS		12,973	TRADE SECRET DATA ENDS]

It is apparent from the table that the natural gas conversion would provide advantages for the facility under the ARP cap-and-trade program. SO_2 emissions associated with firing natural gas are minimal, and OTP would have a significant number of excess SO_2 allowances that could be banked or sold to other ARP-affected facilities.

2.6 CLEAN AIR INTERSTATE RULE AND THE TRANSPORT RULE

On March 10, 2005, EPA issued the Clean Air Interstate Rule (CAIR). CAIR required 28 eastern states and the District of Columbia to reduce emissions of SO_2 and NO_X, because emissions from those states were found to contribute to fine particulate matter ($PM_{2.5}$) and ground level ozone nonattainment in downwind states. States subject to CAIR were required to reduce emissions of SO_2 and NO_X from existing sources, including EUSGUs. CAIR allowed states to demonstrate compliance with emission reduction requirements by establishing a cap-and trade program for SO_2 and NO_X allowances. States subject to the CAIR emission reduction requirements are shown in Figure 2-1. As South Dakota is not as CAIR-affected state, emission sources in South Dakota are not subject to the CAIR emission trading programs.

Figure 2-1. CAIR States



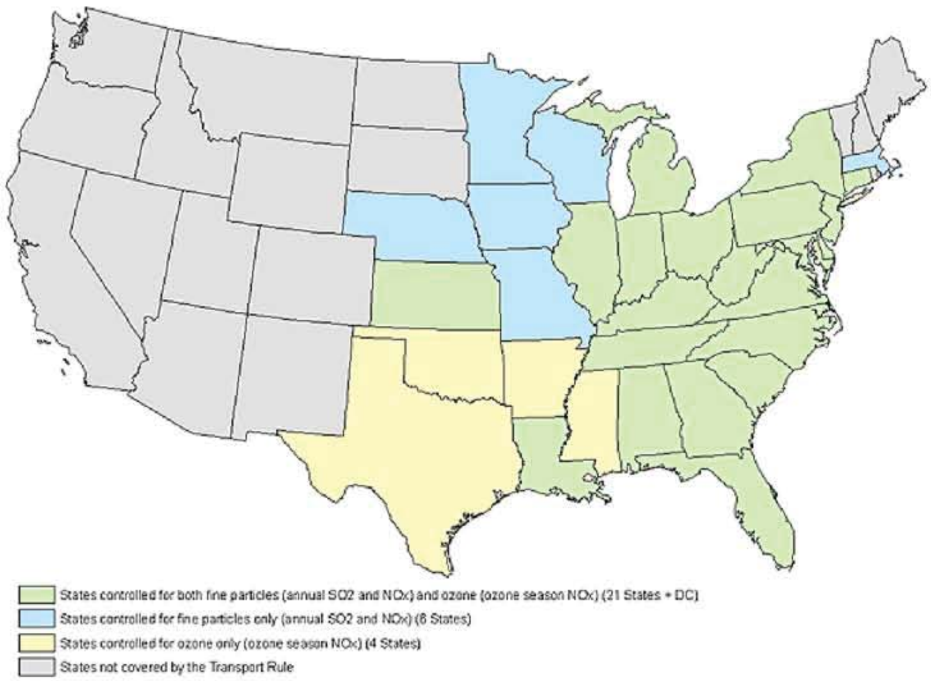
Source: http://www.epa.gov/cair/

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia found that the CAIR was "fundamentally flawed" and issued an order to vacate the rule in its entirety. Subsequently, the Court granted EPA's petition to remand the rule to EPA without vacatur. As a result, CAIR went into effect on January 1, 2009, and will remain in effect until the EPA rewrites the rule to address the flaws identified by the Court.

On July 6, 2010, EPA proposed the Transport Rule (75 FR 45210). The proposed rule would replace the 2005 CAIR, and address the Court's concerns regarding CAIR. Like CAIR, the Transport Rule is intended to implement the Clean Air Act requirements concerning the transport of air pollutants across state boundaries, and assist downwind states to attain and maintain the National Ambient Air Quality Standards for ozone and $PM_{2.5}$.

The proposed Transport Rule used air quality modeling to determine whether each state contributed to downwind air quality problems. If a state's contribution did not exceed specific thresholds, its contribution was found to be insignificant and it was no longer considered in the analysis. Based on the modeling, EPA proposed finding that emissions of SO_2 and NO_X in 32 eastern states contribute significantly to nonattainment in at least one downwind state. States identified in the proposed Transport Rule are shown in Figure 2-2. Emissions from South Dakota sources did not exceed EPA's impact thresholds; therefore, unless the final Transport Rule changes significantly from the proposed rule, emission sources in South Dakota will not be not subject to the Transport Rule emission reduction programs.

Figure 2-2. Transport Rule States



Source: http://www.epa.gov/airtransport/

2.7 SUMMARY

Conclusions relating to the environmental regulatory review are as follows:

- It is unlikely that maximum hourly emissions of NO_X, SO_2, or PM would increase as a result of the project; therefore, it is unlikely that the conversion would trigger applicability of the most recent Subpart Da NSPS requirements.
- It is unlikely that the project would result in a significant increase in annual emissions of any NSR-regulated pollutants (including NO_X, SO_2, CO, VOC, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHG emissions). Annual emissions of SO_2, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHGs would be expected to decrease significantly. Annual NO_X emissions are a function of the controlled NO_X emission rate; however, even without post-combustion NO_X control, annual NO_X emissions would be expected to decrease. CO and VOC emission changes will be a function of the baseline and post-conversion emission rates, heat inputs, and capacity factors used in the netting calculation.

- In the event that it is determined that PSD is triggered for CO and/or VOC emissions, BACT would require combustion controls designed to minimize CO/VOC formation, and could require post-combustion catalytic oxidation control.

- Converting Big Stone Unit 1 to natural gas would significantly reduce annual SO_2 emissions, and generate ARP allowances that could be sold to other ARP-affected units.

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- Modeled visibility impacts on Class I Areas should be below the 0.5-dv threshold, even at the higher post-conversion NO_X emission rates. Visibility impact modeling would be needed to quantify impacts at the various NO_X emission rates. For this study, it was assumed that post-conversion NO_X emissions would need to be controlled to an emission rate of , or less (the proposed Big Stone Unit 1 BART limit). TRADE SECRET DATA ENDS]

- Stationary sources located in South Dakota are not subject to the CAIR cap-and-trade programs, or the proposed Transport Rule regulations.

3. NATURAL GAS FIRING

This section of the report provides a preliminary, high-level description of natural-gas-firing equipment and other systems required for the fuel conversion. Fuel switching to natural gas from coal generally changes boiler and other plant operations significantly.

3.1 GENERAL

Firing natural gas eliminates slagging/fouling conditions, which improves boiler cleanliness and tends to increase heat absorption. However, combustion zone radiation rates to the furnace walls tend to be lower. There are a variety of heat transfers modes in the boiler that are fairly complicated. Achieving design steam temperatures and full boiler output can be difficult. A boiler thermal/convection-pass study performed by a boiler original equipment manufacturer (OEM) is required. The cost estimate provided in this study includes boiler computer modeling and pressure part modifications based on an initial assessment of this boiler.

Coal and ash handling equipment are no longer required if firing natural gas fuel. As such, Big Stone Unit 1 operating staff could likely be reduced, which would reduce operating costs, but natural gas fuel costs can be significant. Forced draft (FD) and induced draft (ID) fans and other boiler auxiliary equipment are usually compatible with firing natural gas.

3.2 NATURAL GAS FIRING IMPACTS ON BOILER

3.2.1 Boiler Modifications and Natural Gas Piping

Fuel switching from coal to natural gas would require the following:

- Cyclone burners would be modified by adding new natural gas burners.
  - — A header with natural gas nozzles located downstream of the cyclone velocity damper would be added.
  - — The refractory and studs would be removed for 100% natural gas operation.
  - — Minor modifications would be made to the cyclone re-entrant throats/slag tap direction to help minimize particle erosion in the cyclone burner (assist flue gas from leaving the cyclone burner).
- Coal piping near the cyclone burners would be removed and the remainder would be left in place.

- New natural gas igniters, scanners, cooling air, and associated equipment/components would be required.
- SOFA system would be installed.
- New main natural gas supply piping from the source to the fence line would be included.
- New main natural gas supply piping from the existing natural gas header to the burners and burner system piping per NFPA 85 Code would be installed.
- All boiler coal firing, coal handling system equipment, sootblowers, and ash handling equipment would be retired in place. The scope to remove this equipment is not included in the cost estimate.
- The boiler would be converted to fire only natural gas, with no provisions to fire other fuels in the future.
- A boiler thermal computer analysis should be conducted by a boiler supplier to verify that the heat absorption rates and tube and steam temperatures are proper. The boiler thermal study will provide the necessary input for pressure part modification through the convection pass. It is expected that pressure parts will need to be modified with converting to natural gas.
- Boiler implosion/reinforcement modifications (buckstay modifications) would be required.

3.2.2 Estimated Boiler Performance

The net turbine heat rate stated in the previously noted S&L report[2] was used in the estimated performance calculations. The Big Stone Unit 1 estimated performance calculations for the natural gas-fired case are summarized in Table 3-1.

[TRADE SECRET DATA BEGINS

Table 3-1. Natural Gas Firing Performance Summary

Parameter	Performance
Gross plant output (kW)	
Auxiliary power (kW)	
Boiler efficiency (%)	
Net plant output (kW)	
Net plant heat rate (Btu/kWh-net)	
Full-load heat input (mmBtu/hr)	
Full Load NG Fuel Feed Rate, (lb/hr)	

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[2] SO_2, NO_X, and Mercury Reduction Study, *Conceptual Engineering Study Report*, Draft SL-010408, September 24, 2010.

Based on S&L's preliminary boiler performance calculations, it can be concluded that the natural gas conversion will not result in an increased maximum full-load heat input to the boiler, and that the maximum hourly heat input to the boiler will remain below the current descriptive operating limit in the facility's operating permit of 5,609 mmBtu/hr.

3.2.3 Main Natural Gas Piping [TRADE SECRET DATA BEGINS

A high-level cost estimate for a natural gas pipeline to the fence line is provided for in the capital cost estimate. The cost estimate includes material, labor and general right-of-way costs.
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A new gas regulating station and main natural gas supply piping and burner system piping per NFPA from the property line to the boiler is provided for in the capital cost estimate.

3.2.4 Fuel Trip Furnace Negative Pressure Transients - Boiler Implosions

Conversion to firing natural gas will result in greater furnace negative pressure excursions when the boiler trips from 75% or higher unit output. The fuel cutoff and furnace flame collapse, when firing natural gas, will be much faster compared to firing coal. Therefore, boiler furnace and other structural modifications are typically needed for firing natural gas. The furnace section of the boiler has a steady-state deign pressure of +3"/-7" WG, but the transient design pressure of the furnace is unknown. Similarly, the economizer section of the boiler has a steady-state design pressure of -23" WG, but the transient pressure design limit of the furnace economizer section is unknown. The Big Stone Unit 1 furnace has experienced a master fuel trip (MFT) transient exceeding -10"WG.
[TRADE SECRET DATA BEGINS

Boiler manufacturers typically recommend reinforcing the furnace to WG, but insurance companies do not typically require furnace reinforcement to WG. Furnace reinforcement to WG is a reasonable criterion based on a brief review of the requirements. Insurance carriers have agreed with this level of protection on past projects. It is suggested that OTP discuss this proposed level of protection with the insurance carrier.

Based on the recommendation provided in the previously noted report by S&L, reinforcement of the furnace to at least WG is required. Input obtained from was included in that report and a budgetary capital costs for boiler reinforcement to WG are included in the capital cost estimate herein.

An estimated budgetary capital cost for furnace reinforcement to WG is not available without a more detailed study by the original boiler supplier . However, the cost is expected to be significantly higher since furnace
TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS

reinforcement to WG is expected to require buckstay replacement, roof support modifications, and windbox modifications. TRADE SECRET DATA ENDS]

3.2.5 Flue Gas Recirculation

[TRADE SECRET DATA BEGINS

Flue gas flow rates through the boiler without the use of CFGR fans when firing natural gas are typically lower than rates when firing coal. Introducing of recirculating flue gas into the windbox will increase flue gas flow rates through the furnace and convection/back pass, which will increase heat absorption and tube metal temperatures. Excessive flue gas flow velocity through the SH, RH, and economizer should not be a significant issue since there no ash would be present to cause erosion. Costs for a thermal/convection-pass engineering study of the boiler surface are included in the cost estimate to determine if any boiler tube modifications (material and/or additions) are needed with higher tube metal temperatures.

Introducing of recirculating flue gas into the cyclone, in addition to SOFA, should reduce NO_X emission to . Furnace exit flue gas temperatures (FEGT) is expected to be slightly lower than when firing with coal.

Big Stone Unit 1 currently has an FFGR system to control main steam and reheat temperatures. The boiler currently operates using only one of the two gas recirculation fans. It is possible to continue the use of the FFGR system to help maintain design flue gas flow rates though the furnace and convection pass to achieve full-unit output. FFGR will not be effective in NO_X reduction.

Operating the unit without the use of CFGR or FFGR may limit unit output by approximately 90%. Furnace flue gas exit temperatures firing natural gas are expected to be higher (possibly by 100°F) without the use of CFGR but with flue gas flow rates slightly lower than design. Heat transfer through the convection pass, especially to the RH will be affected. NO_X emission of is expected with only a fuel switch to natural gas (no CFGR and SOFA). Modifications to the heating surfaces are typical to achieve 100% unit output. TRADE SECRET DATA ENDS]

3.2.6 Boiler Pressure Parts

Fuel switching to natural gas from coal will significantly affect boiler operation, primarily by improving boiler cleanliness and heat absorption. Improved boiler cleanliness and increased FEGT will cause concern regarding boiler tube metal temperatures. Overall, it is anticipated that main and reheat temperatures would increase with firing natural gas and an increase in attemperation would be expected to help maintain design main steam/reheat outlet temperatures. It is assumed that the current attemperators, valves, and piping are capable of operating at their original design condition and will be of sufficient capacity to control steam temperatures.

3.2.7 Furnace and Convection Pass Heat Absorption Differences

Firing with natural gas will eliminate furnace and convection pass slagging/fouling, which will tend to improve boiler cleanliness and increase heat absorption. Major performance changes for the main boiler heat absorbing surfaces are briefly described below. It is important to understand that the combustion flue gas flow from the furnace through the superheater, reheater and economizer is a fairly complex series of heat absorption stages. Accurately determining boiler performance with natural gas firing is the result of the applicable relationships of this series of heat-absorbing surfaces, which will require computer modeling and detailed boiler design. Flue gas recirculation, burner location and heat release, and other factors also have to be considered. The preliminary observations discussed below are provided based on maintaining the current boiler output, on S&L's experience, and on an initial assessment of this boiler.

3.2.7.1 Furnace Heat Absorption

The natural gas combustion zone heat energy radiation rate to the furnace walls is lower than with coal tending to lower furnace heat absorption, but the furnace walls are cleaner without the coal ash and slagging that tends to increase heat absorption. These two offsetting characteristics tend to result in similar furnace heat absorption rates as for firing coal with clean furnace walls. Therefore, with natural gas firing, steam generation rates and the furnace exit flue gas exit temperatures are often similar to coal firing.

3.2.7.2 Radiant Steam Surface

Radiant steam surfaces and the initial convection surfaces near the exit of the furnace tend to have higher heat absorption rates than with coal. This tends to cause high superheater metal and steam temperatures that require increased attemperation, flue gas recirculation, steam tube replacement, and/or boiler output derating.

3.2.7.3 Convection Pass Superheater, Reheater, and Economizer Surface

With natural gas firing, the superheater, reheater and convection surfaces tend to have higher absorption rates because the slagging, fouling, and ash coatings that inhibited heat transfer will not be present. Improvements to design steam temperatures are expected, although modifications to the tube materials are needed.

3.2.7.4 Steam Temperature Control

Boiler cleaning with sootblowers would be discontinued with natural gas firing. When firing coal, steam temperatures are partially controlled by operating the appropriate sootblowers. When firing natural gas, this option to control boiler heat absorption would be eliminated, thereby, heightening the importance of flue gas recirculation and attemperation.

3.2.7.5 Flue Gas Recirculation

FFGR and/or CFGR are expected to achieve reasonable radiant steam and convection-pass tube metal temperatures with design steam flow. Converting the unit to fire 100% natural gas without FFGR or CFGR would derate boiler steam output to approximately 90%.

3.2.7.6 Attemperation

Increased feedwater superheater attemperation flow is usually required with natural gas firing because of the increased tubing heat absorption rate without slagging, fouling, and ash coating. However, the Big Stone Unit 1 boiler has a large furnace because of the original lignite fuel design and the current main steam temperatures are often about 20°F below design. Therefore, it is currently anticipated that there will be no need to modify the current attemperator design for natural gas.

3.2.7.7 Computer Modeling

Designing the boiler for natural gas firing would include the above. A computer model would be needed to determine the new boiler operating parameters.

However, the input to these models is important. Furnace heat absorption rates for new boilers are often inputted values because computer modeling / calculations have not been sufficiently developed for accurate detailed design. With natural gas firing in an existing coal boiler, especially with a cyclone boiler, there is more uncertainty because of a lack of industry experience with this type of modification.

Boiler thermal modeling provides calculated tube temperatures and stresses and a comparison with boiler code requirements for each boiler surface and the specific tube material and wall thickness. This information shows where modifications are required. Additionally, the current metallurgical condition and the extent of erosion and corrosion of these surfaces have to be analyzed. Typically, higher-alloy or thicker tubes are required for the final superheater and, sometimes, the reheater.

3.2.8 Fan Performance [TRADE SECRET DATA BEGINS

Based on limited review of FD fan design and operating information, it was assumed that the FD fans are operating at design conditions and have sufficient pressure margin for CFGR. ID fan performance should be adequate for firing natural gas with removal of the fabric filters in the baghouse to compensate the change in pressure with the SCR. TRADE SECRET DATA ENDS]

3.2.9 Air Heater Leakage [TRADE SECRET DATA BEGINS

Plant data indicate an average air heater leakage of . AH performance should be adequate for firing natural gas. TRADE SECRET DATA ENDS]

3.2.10 Balance-of-Plant, Electrical, and Instrumentation and Controls

The unit DCS controls would have to be reprogrammed for firing natural gas. New control and electrical cables would be required for the new natural gas burners and associated equipment.

3.2.11 Expected NO_X Emissions [TRADE SECRET DATA BEGINS

A preliminary analysis was conducted that estimates the NO_X and CO emissions with new natural gas burners, new SOFA, and CFGR or FFGR when converted to firing 100% natural gas.

Note that firing 100% natural gas will produce only thermal NO_X emissions. Thermal NO_X is formed by gas-phase chain reactions initiated between oxygen radicals and molecular nitrogen. Combustion calculations show that thermal NO_X will be produced at a rate less than 10 ppm/sec. when the combustion temperature is less than 2500°F and O_2 is 0.04 (mole fraction). Temperatures less than 2500°F, consequently, have minimal affect on the production of thermal NO_X emissions. Therefore, CFGR has a significant impact on thermal NO_X production by reducing peak flame temperatures. The limitation to the percentage of CFGR introduced in the combustion air stream is the minimum windbox O_2 (%) that will have a cutoff of approximately due to the impact on flame stability. TRADE SECRET DATA ENDS]

Thermal NO_X emissions can be correlated with the Heat Release in the Burner Zone Area (HRBZA). The Big Stone Unit 1 furnace is moderately tight, with an HRBZA that is below average, which would tend to have higher than normal emissions (i.e., NO_X) compared with other units with an average HRBZA.

3.2.11.1 Expected Emissions with Flue Gas Recirculation System [TRADE SECRET DATA BEGINS

The installation of new gas burners with the new SOFA port nozzles and with the introduction of CFGR would reduce NO_X emissions below current emission levels. The limitations would be the amount of FCGR that can be introduced without lowering the windbox O_2 level below due to the impact on flame stability. Therefore, it is conservatively estimated that there will be a maximum level of CFGR. This will also result in the existing fans having sufficient capacity.

Based on the results of this initial analysis, it is estimated that the NO_X emissions limit achievable on Big Stone Unit 1 with the combination of new natural gas burners, SOFA, and FFGR to maintain full unit output, would be in the range of with CO levels below . NO_X emissions with combination of new natural gas burners, SOFA, and CFGR would be below with CO levels below .
TRADE SECRET DATA ENDS]

3.2.11.2 Expected Emissions with SCR [TRADE SECRET DATA BEGINS

The installation of an in-line SCR system would reduce NO_X emissions even further from the expected emissions listed above. It is estimated that the NO_X emissions achievable on Big Stone Unit 1 with the combination of new natural gas burners, SOFA, CFGR or FFGR, and SCR would be , which corresponds to the South Dakota requirement. TRADE SECRET DATA ENDS]

3.2.12 Cycling

Cycling operation might be required when switching to natural gas firing because of cost and availability considerations. Cycling of units that are designed for base load operation typically requires major modifications to the boiler, turbine, water treatment system, controls, large motors, piping systems, and other plant components to avoid long startup times that require appreciable fuel and operator time. The capability to accurately predict that the unit will be needed approximately 30 hours before full output is needed is another consideration.

One of many cycling operation impacts is increased boiler header and tubing stress cycling. During a warm re-start, the SH and RH tubing and headers will experience differential surface temperatures compared to the interface surface at wall and roof penetration sealing points, which will remain near the saturation temperature. The headers will shrink/retract as temperatures decrease during a load reduction or shutdown "bottled" condition (and the opposite upon re-starting). This differential expansion will increase the stresses and number of stress cycles on the tube to header connections, particularly at the end points, where the differential movements will be greatest. A flexible header connection design is often necessary in order to "take up" this extra movement and not transfer undue stresses to the header and tube attachment points.

Determining the requirements for cycling operation requires analysis of the boiler, turbine, water treatment system, controls, large motors, piping systems, and other plant components on the unit. A boiler/turbine bypass startup system and control system modifications may be required to reduce unit startup costs and to minimize thermal stresses. A more detailed study would be required on a unit-specific basis to determine the limitations and changes that would be required for cycling operation. Based on general experience, S&L has included a capital cost for installing cycling capability with gas firing at Big Stone.

3.2.13 Schedule [TRADE SECRET DATA BEGINS

The scope of work for a natural gas conversion requires approximately from start of work to commercial operation, with an outage duration of approximately , which includes burner and pressure part modifications. Natural gas piping and flue gas recirculation ductwork and fan installation is typically accomplished during pre-outage.

3.2.14 Impact on O&M Costs and Labor

The fixed O&M for a typical coal unit is about per kilowatt per year, based on several variables, e.g., number of units, age of units, degree of unionization, management practices, and other factors. S&L estimates that about of that cost would be eliminated for a coal plant converted to operation on natural gas. The cost reduction would include elimination of the ash handling and coal handling and a reduction in water treatment and other expenses. The total savings are estimated to be approximately kW/year in fixed O&M cost. Difference in fuel cost has not been included. TRADE SECRET DATA ENDS]

4. UNIT 1 NATURAL GAS CONVERSION COST ESTIMATE

[TRADE SECRET DATA BEGINS

Capital cost estimate line items for converting Big Stone Unit 1 to firing 100% natural gas are listed below. The preliminary engineering and design development for this cost estimate is consistent with an initial assessment and an order-of-magnitude level of accuracy of %. Key notes and assumptions for the estimate are as follows:

- Review of limited equipment design information and operating data was performed. TRADE SECRET DATA ENDS]
- This study was developed without specific solicitations to the boiler supplier or other equipment suppliers based on confidentiality requirements.
- Cost estimates will be prepared based on previous estimates; i.e., no preliminary design and no detailed cost estimating development.
- Costs for new natural gas burners and equipment are based on a previous project and on discussions with boiler suppliers.
- CFGR fans and ductwork costs are included. CFGR fan costs are based on estimates from S&L's recent natural gas studies.
- No costs have been provided if OTP decides to use FFGR vs. CFGR. It is assumed that the current FFGR fans are capable of achieving the necessary capacity to achieving full unit output when converted to 100% natural gas.
- The burner area natural gas piping costs are based on an estimate for a prior plant.
- Costs for natural gas piping to site are based on estimates from prior studies.
- Reprogrammed DCS modifications and a new burner management system are included.
- Removals of cyclone burners and adjacent coal pipes are included.
- Electrical power cabling for new burners and integration of existing BOP equipment, such as for the igniters, flame scanner power cable, and drives, is included.
- Coal-related equipment will be retired in place. No costs are included for removal of this equipment.
- Cost for cycling is included.
- Cost for achieving 100% boiler output is included.
- Costs for asbestos or lead paint removal are not included.

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Table 4-1 summarizes the capital costs for the unit modifications. Estimated capital costs include the equipment, material, and labor based on $2010. Escalation costs are included starting from , until , . The underlying assumption is that the contracting arrangement for the project is on a multiple lump sum (not EPC) basis. The capital costs provided herein are based on burning 100% natural gas and include:

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- Equipment and material
- Installation labor
- Erection contractor profit
- General and administration
- Freight
- Sales tax
- Startup and commissioning
- Spare parts
- Indirect field costs and BOP engineering
- Contingency
- Owner's Engineer cost
- Owner's cost
- Escalation

The installed capital costs are based on past S&L natural gas studies.

[TRADE SECRET DATA BEGINS

Table 4-1. Conceptual Capital Cost Estimate Summary (   )

Natural Gas Conversion Modifications	Total Cost Material/Equip/Install
Boiler Modifications	
CFGR System	
Modify Cyclone Burners for Natural Gas	
BMS and DCS	
Boiler Thermal Study	
SOFA	
Implosion Upgrades	
Convection Pass Pressure Part Modification	
Unit Cycling Modifications	
Boiler Natural Gas Piping	
Boiler Gas Supply Piping (within Fence Line)	
SCR	
In-Duct SCR System	
Total Direct Cost	
Construction indirect Cost	
Indirect Cost	
Contingency	
Escalation	
Owners Cost	
Total Project Cost	
Natural Gas Piping to Property Fence Line	
Contingency	
Escalation	
Total Gas Line Cost to Property Fence Line	

Project indirects, escalation, and Owner's costs are consistent with the basis from the S&L report SL-010408.

Converting Big Stone Unit 1 to natural gas would significantly reduce annual SO_2 emissions, and generate ARP allowances that could be sold to other ARP-affected units. TRADE SECRET DATA ENDS]

5. CONCLUSIONS

The major conclusions relating to permitting and boiler design and operation impacts drawn from the study for converting Big Stone Unit 1 to natural gas firing are summarized below.

5.1 PERMITTING IMPACTS

Converting an existing electric utility steam generating unit from coal to natural gas firing subjects the unit to a number of environmental regulations, including NSPS, NSR preconstruction review regulations, and South Dakota air quality emission standards. The SDENR issued a Title V Operating Permit for the Big Stone Generating Station on June 9, 2009 (Permit #28.0801-29). The operating permit sets emission limits applicable to existing emission sources at the facility. Typically, NSR regulations dictate the emission limits and control technologies required for modifications to an existing major source of emissions; however, in the case of Big Stone Unit 1, the South Dakota Regional Haze regulations may require more stringent emission limits.

5.2 DESIGN AND OPERATING IMPACTS

Conclusions relating to the design and operating review are as follows:

- As is typical with boilers of this vintage, water wall, superheater (SH), and/or reheater (RH) tube material and condition issues are typically normal plant maintenance activities. OTP should perform a condition assessment on all major pressure parts to determine the condition of this equipment. Upgrades/modifications are typically needed to the convection pass to achieve 100% unit output when firing 100% natural gas.
- Providing for cycling operation often requires significant boiler, turbine and other modifications and the addition of a turbine bypass system when converting this type of unit to natural gas because of higher fuel costs.
- Boiler computer modeling is recommended to determine the required modifications to achieve 100% unit output when firing 100% natural gas. Converting a coal-fired boiler to 100% natural gas firing would eliminate slagging/fouling and in turn improve boiler cleanliness. The convection pass will see an improvement in heat transfer and an increase in tube temperatures. Boiler computer modeling costs are included in the cost estimate. [TRADE SECRET DATA BEGINS
- Replacing the existing coal burners with new natural gas burners, installing a SOFA system and FFGR for full unit output will achieve NO_X emissions of and CO levels below for 100% unit output. NO_X emissions below and CO levels below are expected with the use of new natural gas burners, SOFA, and CFGR fans. However, SCR is required to achieve NO_X emissions of , which is required by NSPS. TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET - PRIVATE DATA HAS BEEN EXCISED

ATTACHMENT 9

OTTER TAIL POWER COMPANY
BSP PRO FORMA RESULTS LETTER REPORT
NORTH DAKOTA

March 29, 2011

Mr. Mark Rolfes
Manager, Generation Development
Otter Tail Power Corporation
215 South Cascade Street
Fergus Falls, MN 56538

Re: Big Stone Plant Pro Forma Economic Analysis – Modeling Results
BMcD Project No. 57975

Dear Mr. Rolfes:

Burns & McDonnell (BMcD) has been retained by Otter Tail Electric Power Company (Otter Tail) to perform a pro forma economic analysis (Analysis) of the air quality control system (AQCS) proposed to be installed on the existing Big Stone Plant (BSP). The AQCS option will be compared to several alternatives for providing energy from a generation resource other than BSP. The Analysis includes preparing a pro forma economic model for each of the following cases.

- BSP with AQCS
- BSP Retrofitted to Burn Natural Gas (BSP on NG)
- A Combined Cycle Plant to Replace BSP (CCGT)
- A Combined Cycle Plant Combined with Wind Energy Purchases to Match the BSP Energy Production (CCGT + Wind)

Screening level pro forma economic models were prepared to determine the levelized cost of power for each alternative over a 20 year planning period. These levelized energy costs can be compared to one another to determine the relative economic attractiveness of each of the options under consideration.

Modeling Inputs

The following inputs were provided to BMcD from Otter Tail's recently filed Integrated Resource Plan (IRP).

- O&M Inflation 3.0% per annum
- Capital Cost Inflation 4.0% per annum

[TRADE SECRET DATA BEGINS...

- Interest Rate
- Return on Equity
- Discount Rate

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[TRADE SECRET DATA BEGINS...

- o Market Price of Wind Power (2009 $, excluding PTC)

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- o Fuel Cost Forecast — Table 1

[TRADE SECRET DATA BEGINS...

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The following inputs were provided to BMcD based on Otter Tail's internal estimates for the BSP options.

- BSP with AQCS
  - o Net Plant Output — 475 MW
  - o Net Plant Heat Rate — 10,715 Btu/kW
  - o Net Plant Capacity Factor — 75%
  - o Capital Cost of AQCS (2016 $) — $490 million

o Annual O&M Cost (Fixed & Variable 2016 $)	$27.3 million

- BSP on NG

o Net Plant Output	475 MW
o Net Plant Heat Rate	10,023 Btu/kW
o Net Plant Capacity Factor	75%
o Conversion Capital Cost (2016 $)	$147 million
o Annual O&M Cost (Fixed & Variable 2016 $)	$13.0 million

- CCGT and CCGT + Wind

o BSP Decommissioning Cost (2016 $)	$21.3 million

- All Natural Gas Fired Options

o Linear Facility Capital Cost (2016 $)	$120 million

The following inputs were developed by BMcD from recent project experience.

- CCGT

o Net Plant Output	475 MW
o Net Plant Heat Rate	6,680 Btu/kW
o Net Plant Capacity Factor	75%
o Capital Cost (2010 $)	$402 million
o Annual Fixed O&M Cost (2010 $)	$8.50/kW-year
o Annual Variable O&M Cost (2010 $)	$4.30/MWh

- CCGT + Wind

o Combined Cycle Net Plant Output	475 MW
o Combined Cycle Net Plant Heat Rate	6,680 Btu/kW

o Combined Cycle Net Plant Capacity Factor	35%
o Combined Cycle Capital Cost (2010 $)	$402 million
o Combined Cycle Annual Fixed O&M Cost (2010 $)	$8.50/kW-year
o Combined Cycle Annual Variable O&M Cost (2010 $)	$4.30/MWh
o Capacity Factor of Wind Purchases	40%
o Levelized Value of Production Tax Credit (PTC) (2009$)	$20/MWh

The combined cycle cost estimates and performance values presented above for the CCGT and CCGT + Wind options are based on recent project experience. These values are based on a typical cost for an unfired 2 on 1 GE FA.05 combined cycle plant. Although a plant of this type will have an output in the range of approximately 600 MW, only the first 475 MW of capacity was considered in this Analysis, in order to compare the options on a consistent basis. The total capital cost presented above was calculated based on the dollar per kilowatt installed cost of an unfired 2 on 1 GE FA.05 combined cycle plant, multiplied by 475 MW. The heat rate values presented above are based on typical unfired 2 on 1 GE FA.05 combined cycle plant performance. The annual fixed O&M and variable O&M values are also based on typical unfired 2 on 1 GE FA.05 combined cycle plant costs and the variable O&M values included major maintenance costs.

The capacity factor for wind purchases considered in the Analysis is based on an assumed capacity factor for a typical wind farm in this region of the country. The levelized value of the PTC used in the analysis is based on the current legislation and the impact to the levelized cost of power for a typical wind farm, based on recent project experience.

Base Case Results

Each of the alternatives listed above was evaluated in a pro forma economic model to determine a screening level energy cost. These costs can be compared to determine the relative economic attractiveness of each of the alternatives considered.

The capital and O&M costs for BSP with AQCS and BSP on NG were provided to BMcD by Otter Tail in 2016 dollars. These values were input directly into the model without additional escalation applied, other than annual O&M escalation for year to year operations. The year to year escalation rate of three percent was used consistent with Otter Tail's IRP filing.

Capital and O&M costs for the CCGT option were taken from recent BMcD experience. These values were developed in 2010 dollars, and were escalated four percent per year for capital and three percent per year for O&M to 2016 dollars, consistent with Otter Tail's IRP modeling assumptions.

In the CCGT + Wind case, BMcD estimated that a 40% capacity factor could be provided by market wind energy purchases. The $71/MWh cost of market wind energy purchases in 2009 dollar provided by Otter Tail was used as a starting point to determine the price of market wind energy to use in this Analysis. The CCGT + Wind option evaluated in the base case included the value of the PTC. No option was considered in the base case without the PTC. A value of the PTC of $20/MWh in 2009 dollars was deducted from the market wind energy purchases price to arrive at a 2009 cost of wind power of $51/MWh including the value of the PTC. This value was escalated by four percent per year to 2016 dollars resulting in a levelized market price of wind energy of $67.11 to use in the economic modeling. The remaining energy would be produced by a combined cycle plant. For purposes of this Analysis, a 475 MW combined cycle plant was utilized, equivalent to BSP. This facility would operate at a 35 percent capacity factor to achieve an annual energy production equivalent to BSP. Current combustion turbine technology results in combined cycle plant net capacities in the range of 615 MW. The capital cost in this Analysis was based on the dollar per kilowatt estimates from for a 615 MW facility, assuming that Otter Tail would own a 475 MW share in a facility of this size.

For each of the alternatives to BSP with AQCS, $120 million was added to cover the costs of linear facilities required to support the project. This would cover the costs to run a new natural gas line to the BSP plant to convert the units to burn natural gas or construct a new combined cycle plant at that site. Alternatively, if a new combined cycle facility were to be constructed at another site, linear infrastructure would need to be constructed for natural gas, transmission service, and possibly water and discharge pipelines.

For the CCGT and CCGT + Wind options a cost of $21.3 million was also added to the capital costs to cover the decommissioning costs for BSP.

In addition to the decommissioning costs, Otter Tail estimated that an $82 million cost should be assigned to the CCGT and CCGT + Wind options to cover stranded asset costs if BSP would cease to operate. This cost represents the current book value of BSP. However, the economic modeling for the BSP with AQCS and BSP on NG options does not account for this remaining book value to be depreciated going forward. The BSP with AQCS and BSP on NG options only account for the capital cost to add the new AQCS equipment or to convert to fire with natural gas. The stranded asset cost was not included in the base case values, however this cost was

Mr. Mark Rolfes
Otter Tail Power Corporation
March 29, 2011
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modeled as an additional scenario to determine the impact it would have on the energy cost. It was determined that this scenario would add $3.81/MWh to the levelized energy cost for the CCGT and CCGT + Wind options.

Otter Tail also requested that BMcD consider the impact of a high environmental cost scenario. This scenario consists of the inclusion of mercury emissions control requirements and potential ash regulations. Otter Tail provided a $5 million additional capital cost and $2 million per year additional O&M cost to be included for mercury removal on the BSP with AQCS option. Also, $6.66 million in additional O&M was provided for handing ash if it is categorized as a hazardous waste. These three additional costs resulted in a $3.66/MWh increase in the levelized cost of energy for the BSP with AQCS option.

The results of the modeling using the base case assumptions are provided in Table 2 below.

Table 2 – Economic Modeling Base Case Results

20-YEAR LEVELIZED BUSBAR COSTS		BSP + AQCS	CCGT + Wind with PTC	CCGT	BSP on NG
Operations Summary					
Net Dispatchable Capacity (MW)		475	475	475	475
Net Dispatchable Generation Capacity Factor		75%	35%	75%	75%
Net Dispatchable Energy Generation (MWh)		3,120,750	1,456,350	3,120,750	3,120,750
Net Wind Capacity Factor		-	40%	-	-
Net Wind Energy Market Purchases (MWh)		-	1,664,400	-	-
Capital Cost (2016 $)		$ 490,000,000	$ 621,289,115	$ 621,289,115	$ 267,000,000
Depreciation & Interest Basis Energy Costs					
Fuel	(2016$ / MWh)	$ 40.68	$ 66.44	$ 66.44	$ 99.70
O&M	(2016$ / MWh)	$ 12.09	$ 13.37	$ 9.55	$ 5.78
Depreciation	(2016$ / MWh)	$ 8.56	$ 23.25	$ 10.85	$ 4.66
Return	(2016$ / MWh)	$ 6.10	$ 16.58	$ 7.74	$ 3.32
Interest	(2016$ / MWh)	$ 4.91	$ 13.34	$ 6.22	$ 2.68
Income Taxes	(2016$ / MWh)	$ 2.03	$ 5.53	$ 2.58	$ 1.11
Levelized Revenue Requirement	**(2016$ / MWh)**	**$ 74.38**	**$ 138.50**	**$ 103.38**	**$ 117.25**
Cost of Wind Energy	**(2016$ / MWh)**	**$ -**	**$ 67.11**	**$ -**	**$ -**
Combined Levelized Energy Cost	**(2016$ / MWh)**	**$ 74.38**	**$ 100.43**	**$ 103.38**	**$ 117.25**
Stranded Asset Cost Scenario Adder	**(2016$ / MWh)**	**$ -**	**$ 3.81**	**$ 3.81**	**$ -**
Total Energy Cost Including Stranded Asset Cost	**(2016$ / MWh)**	**$ 74.38**	**$ 104.24**	**$ 107.19**	**$ 117.25**
High Environmental Cost Scenario Adder	**(2016$ / MWh)**	**$ 3.66**	**$ -**	**$ -**	**$ -**
Total Energy Cost Including High Environmental Cost	**(2016$ / MWh)**	**$ 78.04**	**$ 100.43**	**$ 103.38**	**$ 117.25**

Based on the results of the base case Analysis presented above, BSP with AQCS is the most economically attractive alternative under the base case assumptions. The second most attractive alternative is the CCGT + Wind option, however, this option results in a 35 percent higher cost of energy than BSP with AQCS. Adding in the stranded asset costs to the CCGT + Wind option increases the differential in cost of energy between these two options to 40 percent. Adding in the high environmental cost scenario adder reduces these differentials in levelized energy costs to 29 percent and 34 percent respectively.

Sensitivity Analysis

A sensitivity analysis was prepared for each of the alternatives evaluated in the Analysis under the following cases:

- Capital Cost (plus or minus 30%)
- Fuel Cost (plus or minus 20%)
- O&M Costs (plus or minus 20%)

A sensitivity analysis was performed to determine the impact of changes to the capital costs of each option. The results of the capital cost sensitivity analysis are presented in Figure 1 below.

Mr. Mark Rolfes
Otter Tail Power Corporation
March 29, 2011
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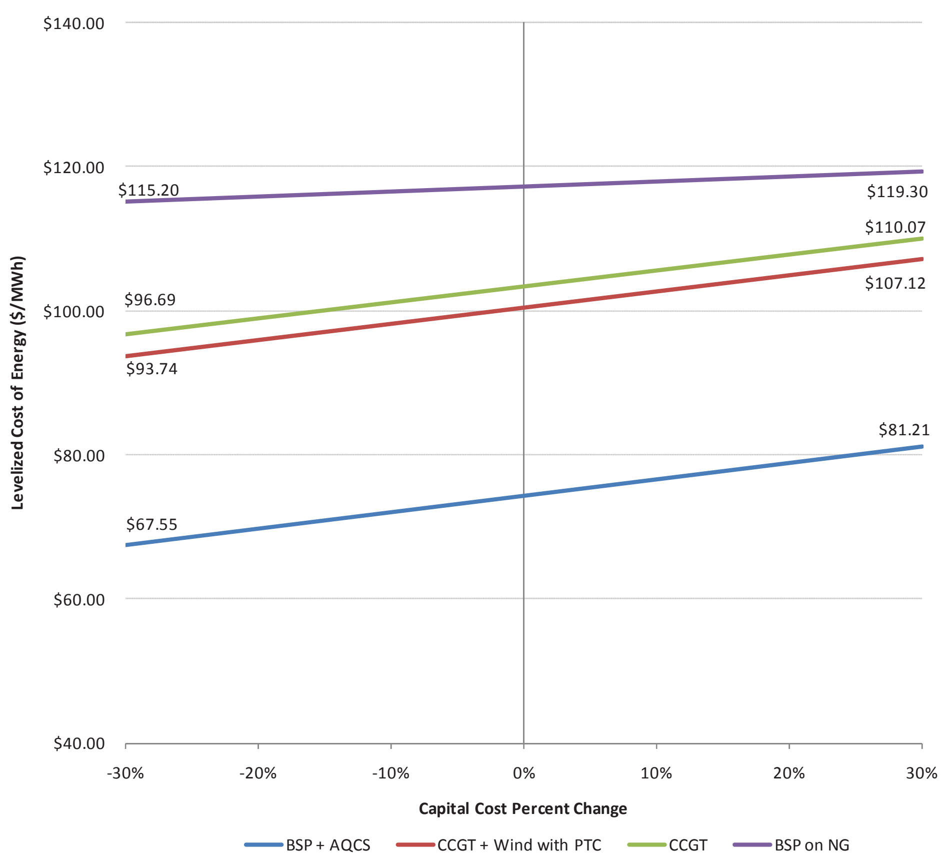
Figure 1 – Capital Cost Sensitivity Levelized Energy Costs



Over the range of capital costs evaluated in this sensitivity analysis, the BSP with AQCS option is preferred in all instances. Capital cost changes have a similar impact on BSP with AQCS, CCGT and CCGT + Wind options, since they all have relatively similar capital costs. Capital cost changes have the least impact on the BSP on NG option, since it requires the least capital cost investment.

A sensitivity analysis was performed to determine the impact of changes to the fuel costs for each option. The results of the fuel cost sensitivity analysis are presented in Figure 2 below.

Mr. Mark Rolfes
Otter Tail Power Corporation
March 29, 2011
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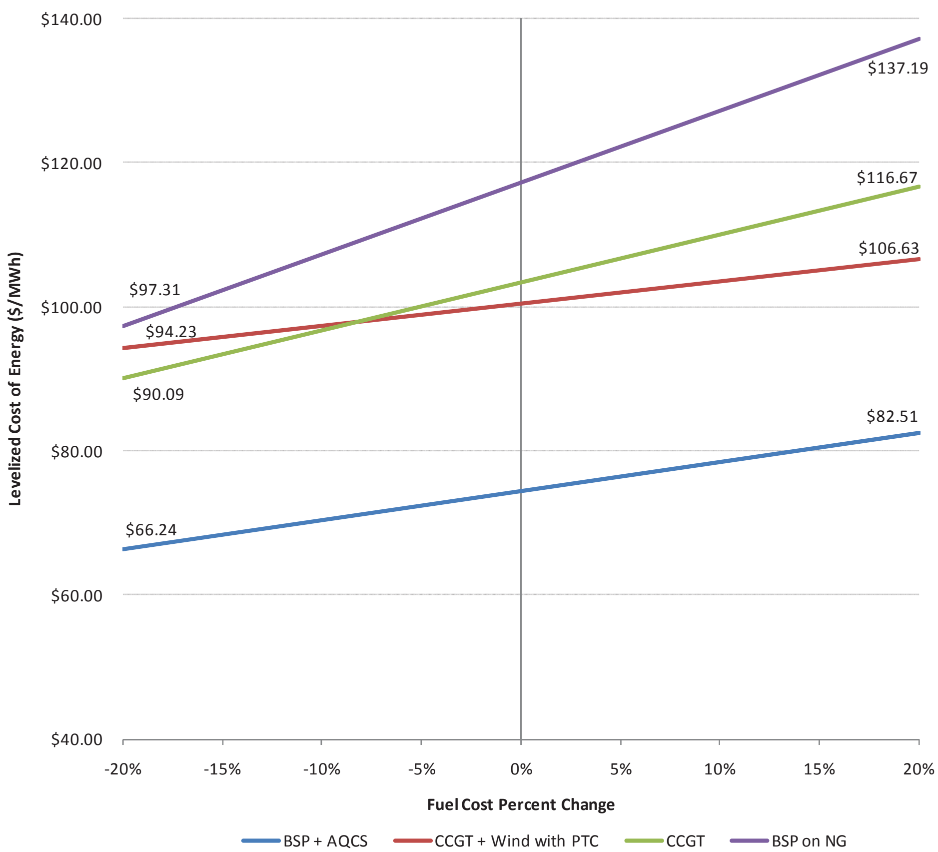
Figure 2 – Fuel Cost Sensitivity Levelized Energy Costs



Over the range of fuel costs evaluated in this sensitivity analysis, the BSP with AQCS option is preferred in all instances. Fuel cost changes have the largest impact on the natural gas-fired options, since natural gas has a much higher base case cost than coal. The impact or fuel cost changes is reduced on the CCGT + Wind case, since more than half of the energy in that case is provided from wind power generation, which is unaffected by changes in fuel prices.

A sensitivity analysis was performed to determine the impact of changes in O&M costs for each of the options. The results of the O&M cost sensitivity analysis are presented in Figure 3 below.

Mr. Mark Rolfes
Otter Tail Power Corporation
March 29, 2011
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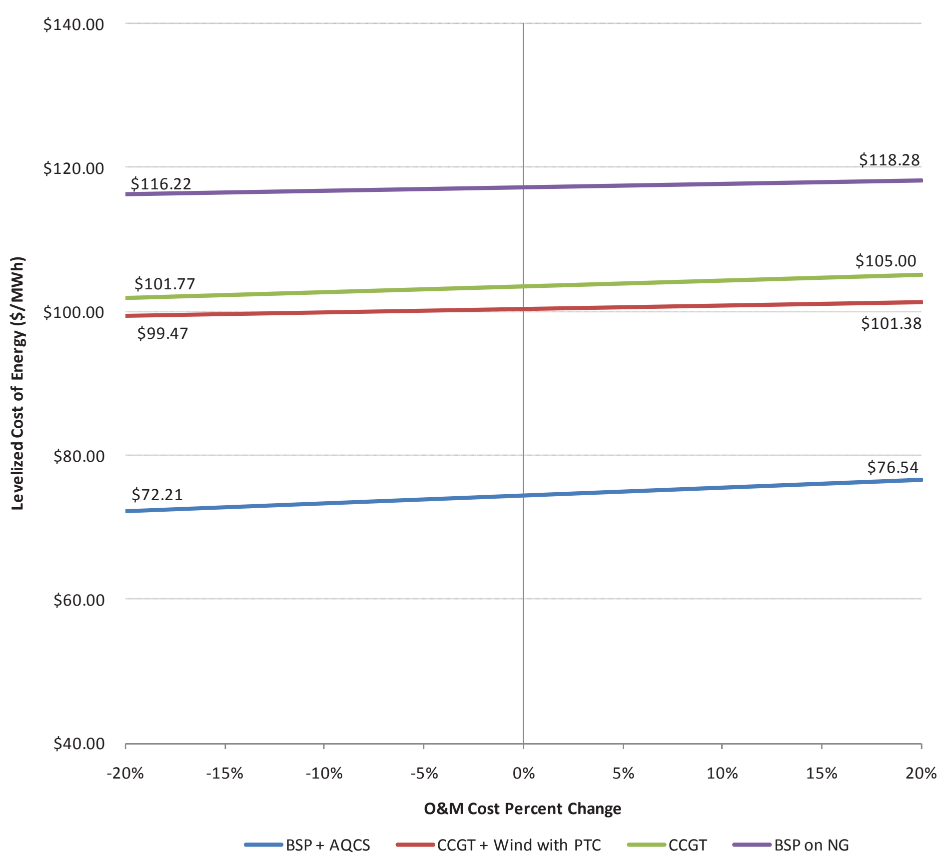
Figure 3 – O&M Cost Sensitivity Levelized Energy Costs



Over the range of O&M costs evaluated in this sensitivity analysis, the BSP with AQCS option is preferred in all instances. O&M cost changes have relatively insignificant impacts on all of the options considered.

Mr. Mark Rolfes
Otter Tail Power Corporation
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Page 11

Conclusions

Based on the results of this Analysis, the BSP with AQCS is the most economically attractive alternative of the options considered for BSP under the potential future scenarios evaluated. The BSP with AQCS option results in a significantly lower levelized cost of energy than the other options evaluated under the base case assumptions. BSP with AQCS option remains economically attractive relative to the other options considered over the range of sensitivities evaluated in this Analysis.

The impact on other Otter Tail resources and Otter Tail's integrated resource plan (IRP) was not evaluated in this Analysis. Otter Tail will need to determine how a change of resource type at the BSP site would impact other resources in Otter Tail's generation portfolio, as well as how a new resource would fit into Otter Tail's IRP.

If you have any questions regarding the results of this Analysis, please call Jeff Greig at 816-822-3392 or Jeff Kopp at 816-822-4239 to discuss.

Sincerely,

Jeff Greig
General Manager, Business & Technology Services

Jeffrey T Kopp

Jeff Kopp, PE
Development Engineer

JTK

cc: Mark Rolfes

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September 26, 2011

Reply to Fergus Falls office
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Mr. Darrell Nitschke
Director of Administration/Executive Secretary
North Dakota Public Service Commission
State Capitol
600 East Boulevard Dept. 408
Bismarck, ND 58505

RE: Revised Attachment 9 and Joint Exhibits 2-3

**Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Application for Advance Determination of Prudence Big Stone Air Quality Control System Project
Case No. PU-11-163**

**Otter Tail Power Company Application for Advance Determination of Prudence
Big Stone Air Quality Control System Project
Case No. PU-11-165**

Dear Mr. Nitschke:

Applicants in the above-referenced matters recently discovered that Burns & McDonnell (the engineering firm that performed the pro forma or levelized-cost economic analysis in Attachment 9 of the Applicants' Application materials) had entered an erroneous heat rate input for Big Stone Plant with AQCS in the spreadsheet analyzing the Big Stone Plant with AQCS vis-à-vis generation alternatives.

The heat rate input was a simple, clerical keystroke-error that resulted in analyzing a higher heat rate than is anticipated for the Big Stone Plant with AQCS. When corrected in the spreadsheet, the busbar energy cost for Big Stone Plant with AQCS is projected to be even lower than the original Attachment 9 reflects – and, therefore, more cost-effective vis-à-vis potential generation alternatives.

For filing we have enclosed an original and seven copies of Revised Attachment 9 and Revised Joint Exhibits 2 and 3, with corrected busbar energy cost figures for Big Stone Plant with AQCS. In order to assist the reader in identify revisions made, we are enclosing both clean and redlined versions of Revised Joint Exhibits 2 and 3.

For convenience of parties and the Commission, Revised Attachment 9 may be substituted for the original Attachment 9. Clean Revised Joint Exhibits 2 and 3 with line numbers may be substituted for Joint Exhibits 2 and 3, as originally filed and as filed on September 7, 2011 with line numbering pursuant to Judge Wahl's order.

Enclosed materials should be filed in both PU-11-163 and PU-11-165, and I have been authorized by Montana-Dakota Utilities Co. to so advise. Please feel free to contact me if you have any questions.

Sincerely,

/s/ MARK B. BRING
Mark B. Bring
Associate General Counsel

MBB:wao
By electronic filing
Enclosures

STATE OF MINNESOTA)
) SS.
COUNTY OF OTTER TAIL)

AFFIDAVIT OF SERVICE

RE: Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Application for Advance Determination of Prudence Big Stone Air Quality Control System Project
Case No. PU-11-163

Otter Tail Power Company Application for Advance Determination of Prudence
Big Stone Air Quality Control System Project
Case No. PU-11-165

I, Wendi A. Olson, being first duly sworn on oath, deposes and says: that on the 26th day of September, 2011, I served the attached Revised Joint Exhibits 2 and 3 and the Revised Attachment 9 of Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. and Otter Tail Power Company, on Mr. Darrell Nitschke and the North Dakota Public Service Commission by e-mail and over-night mail and to all other persons list below by email.

Honorable Al. Wahl
Administrative Law Judge
Office of Administrative Hearings
138 East Edmonton Drive
Bismarck ND 58503
aljwahl@gmail.com

Illona A. Jeffcoat-Sacco, Esq.
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/s/ WENDI A. OLSON

Subscribed and sworn to before me this
26th day of September, 2011.

/s/ JENNIFER M. WINNINGHAM-FLODEN

Jennifer M. Winningham-Floden
Notary Public, My Commission Expires on January 31, 2013.

September 19, 2011

Mr. Mark Rolfes
Manager, Generation Development
Otter Tail Power Corporation
215 South Cascade Street
Fergus Falls, MN 56538

Re: Big Stone Plant Pro Forma Economic Analysis – Modeling Results
BMcD Project No. 57975

Dear Mr. Rolfes:

Burns & McDonnell (BMcD) has been retained by Otter Tail Electric Power Company (Otter Tail) to perform a pro forma economic analysis (Analysis) of the air quality control system (AQCS) proposed to be installed on the existing Big Stone Plant (BSP). The AQCS option will be compared to several alternatives for providing energy from a generation resource other than BSP. The Analysis includes preparing a pro forma economic model for each of the following cases.

- BSP with AQCS
- BSP Retrofitted to Burn Natural Gas (BSP on NG)
- A Combined Cycle Plant to Replace BSP (CCGT)
- A Combined Cycle Plant Combined with Wind Energy Purchases to Match the BSP Energy Production (CCGT + Wind)

Screening level pro forma economic models were prepared to determine the levelized cost of power for each alternative over a 20 year planning period. These levelized energy costs can be compared to one another to determine the relative economic attractiveness of each of the options under consideration.

Modeling Inputs

The following inputs were provided to BMcD from Otter Tail's recently filed Integrated Resource Plan (IRP).

- O&M Inflation 3.0% per annum
- Capital Cost Inflation 4.0% per annum

[TRADE SECRET DATA BEGINS…

- Interest Rate
- Return on Equity
- Discount Rate

…TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS...

- Market Price of Wind Power (2009 $, excluding PTC)

...TRADE SECRET DATA ENDS]

- Fuel Cost Forecast — Table 1

Table 1 – Fuel Cost Forecast

Year	Coal ($/MMBtu)	Natural Gas ($/MMBtu)
2016	**[TRADE SECRET DATA BEGINS...**	
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		**...TRADE SECRET DATA ENDS]**

The following inputs were provided to BMcD based on Otter Tail's internal estimates for the BSP options.

- BSP with AQCS
  - Net Plant Output — 475 MW
  - Net Plant Heat Rate — 10,715 Btu/kW
  - Net Plant Capacity Factor — 75%
  - Capital Cost of AQCS (2016 $) — $490 million

- Annual O&M Cost (Fixed & Variable 2016 $) $27.3 million

- BSP on NG
  - Net Plant Output 475 MW
  - Net Plant Heat Rate 10,023 Btu/kW
  - Net Plant Capacity Factor 75%
  - Conversion Capital Cost (2016 $) $147 million
  - Annual O&M Cost (Fixed & Variable 2016 $) $13.0 million

- CCGT and CCGT + Wind
  - BSP Decommissioning Cost (2016 $) $21.3 million

- All Natural Gas Fired Options
  - Linear Facility Capital Cost (2016 $) $120 million

The following inputs were developed by BMcD from recent project experience.

- CCGT
  - Net Plant Output 475 MW
  - Net Plant Heat Rate 6,680 Btu/kW
  - Net Plant Capacity Factor 75%
  - Capital Cost (2010 $) $402 million
  - Annual Fixed O&M Cost (2010 $) $8.50/kW-year
  - Annual Variable O&M Cost (2010 $) $4.30/MWh

- CCGT + Wind
  - Combined Cycle Net Plant Output 475 MW
  - Combined Cycle Net Plant Heat Rate 6,680 Btu/kW

- Combined Cycle Net Plant Capacity Factor 35%
- Combined Cycle Capital Cost (2010 $) $402 million
- Combined Cycle Annual Fixed O&M Cost (2010 $) $8.50/kW-year
- Combined Cycle Annual Variable O&M Cost (2010 $) $4.30/MWh
- Capacity Factor of Wind Purchases 40%
- Levelized Value of Production Tax Credit (PTC) (2009$) $20/MWh

The combined cycle cost estimates and performance values presented above for the CCGT and CCGT + Wind options are based on recent project experience. These values are based on a typical cost for an unfired 2 on 1 GE FA.05 combined cycle plant. Although a plant of this type will have an output in the range of approximately 600 MW, only the first 475 MW of capacity was considered in this Analysis, in order to compare the options on a consistent basis. The total capital cost presented above was calculated based on the dollar per kilowatt installed cost of an unfired 2 on 1 GE FA.05 combined cycle plant, multiplied by 475 MW. The heat rate values presented above are based on typical unfired 2 on 1 GE FA.05 combined cycle plant performance. The annual fixed O&M and variable O&M values are also based on typical unfired 2 on 1 GE FA.05 combined cycle plant costs and the variable O&M values included major maintenance costs.

The capacity factor for wind purchases considered in the Analysis is based on an assumed capacity factor for a typical wind farm in this region of the country. The levelized value of the PTC used in the analysis is based on the current legislation and the impact to the levelized cost of power for a typical wind farm, based on recent project experience.

Base Case Results

Each of the alternatives listed above was evaluated in a pro forma economic model to determine a screening level energy cost. These costs can be compared to determine the relative economic attractiveness of each of the alternatives considered.

The capital and O&M costs for BSP with AQCS and BSP on NG were provided to BMcD by Otter Tail in 2016 dollars. These values were input directly into the model without additional escalation applied, other than annual O&M escalation for year to year operations. The year to year escalation rate of three percent was used consistent with Otter Tail's IRP filing.

Capital and O&M costs for the CCGT option were taken from recent BMcD experience. These values were developed in 2010 dollars, and were escalated four percent per year for capital and three percent per year for O&M to 2016 dollars, consistent with Otter Tail's IRP modeling assumptions.

In the CCGT + Wind case, BMcD estimated that a 40% capacity factor could be provided by market wind energy purchases. The $71/MWh cost of market wind energy purchases in 2009 dollar provided by Otter Tail was used as a starting point to determine the price of market wind energy to use in this Analysis. The CCGT + Wind option evaluated in the base case included the value of the PTC. No option was considered in the base case without the PTC. A value of the PTC of $20/MWh in 2009 dollars was deducted from the market wind energy purchases price to arrive at a 2009 cost of wind power of $51/MWh including the value of the PTC. This value was escalated by four percent per year to 2016 dollars resulting in a levelized market price of wind energy of $67.11 to use in the economic modeling. The remaining energy would be produced by a combined cycle plant. For purposes of this Analysis, a 475 MW combined cycle plant was utilized, equivalent to BSP. This facility would operate at a 35 percent capacity factor to achieve an annual energy production equivalent to BSP. Current combustion turbine technology results in combined cycle plant net capacities in the range of 615 MW. The capital cost in this Analysis was based on the dollar per kilowatt estimates from for a 615 MW facility, assuming that Otter Tail would own a 475 MW share in a facility of this size.

For each of the alternatives to BSP with AQCS, $120 million was added to cover the costs of linear facilities required to support the project. This would cover the costs to run a new natural gas line to the BSP plant to convert the units to burn natural gas or construct a new combined cycle plant at that site. Alternatively, if a new combined cycle facility were to be constructed at another site, linear infrastructure would need to be constructed for natural gas, transmission service, and possibly water and discharge pipelines.

For the CCGT and CCGT + Wind options a cost of $21.3 million was also added to the capital costs to cover the decommissioning costs for BSP.

In addition to the decommissioning costs, Otter Tail estimated that an $82 million cost should be assigned to the CCGT and CCGT + Wind options to cover stranded asset costs if BSP would cease to operate. This cost represents the current book value of BSP. However, the economic modeling for the BSP with AQCS and BSP on NG options does not account for this remaining book value to be depreciated going forward. The BSP with AQCS and BSP on NG options only account for the capital cost to add the new AQCS equipment or to convert to fire with natural gas. The stranded asset cost was not included in the base case values, however this cost was modeled as an additional scenario to determine the impact it would have on the energy cost. It was determined that this scenario would add $3.81/MWh to the levelized energy cost for the CCGT and CCGT + Wind options.

Otter Tail also requested that BMcD consider the impact of a high environmental cost scenario. This scenario consists of the inclusion of mercury emissions control requirements and potential ash regulations. Otter Tail provided a $5 million additional capital cost and $2 million per year additional O&M cost to be included for mercury removal on the BSP with AQCS option. Also, $6.66 million in additional O&M was provided for handing ash if it is categorized as a hazardous waste. These three additional costs resulted in a $3.66/MWh increase in the levelized cost of energy for the BSP with AQCS option.

The results of the modeling using the base case assumptions are provided in Table 2 below.

Table 2 – Economic Modeling Base Case Results

20-YEAR LEVELIZED BUSBAR COSTS		BSP + AQCS	CCGT + Wind with PTC	CCGT	BSP on NG
Operations Summary					
Net Dispatchable Capacity (MW)		475	475	475	475
Net Dispatchable Generation Capacity Factor		75%	35%	75%	75%
Net Dispatchable Energy Generation (MWh)		3,120,750	1,456,350	3,120,750	3,120,750
Net Wind Capacity Factor		-	40%	-	-
Net Wind Energy Market Purchases (MWh)		-	1,664,400	-	-
Capital Cost (2016 $)		$ 490,000,000	$ 621,289,115	$ 621,289,115	$ 267,000,000
Depreciation & Interest Basis Energy Costs					
Fuel	(2016$ / MWh)	$ 37.21	$ 66.44	$ 66.44	$ 99.70
O&M	(2016$ / MWh)	$ 12.08	$ 13.37	$ 9.55	$ 5.78
Depreciation	(2016$ / MWh)	$ 8.56	$ 23.25	$ 10.85	$ 4.66
Return	(2016$ / MWh)	$ 6.10	$ 16.58	$ 7.74	$ 3.32
Interest	(2016$ / MWh)	$ 4.91	$ 13.34	$ 6.22	$ 2.68
Income Taxes	(2016$ / MWh)	$ 2.03	$ 5.53	$ 2.58	$ 1.11
Levelized Revenue Requirement	**(2016$ / MWh)**	**$ 70.89**	**$ 138.50**	**$ 103.38**	**$ 117.25**
Cost of Wind Energy	**(2016$ / MWh)**	**$ -**	**$ 67.11**	**$ -**	**$ -**
Combined Levelized Energy Cost	**(2016$ / MWh)**	**$ 70.89**	**$ 100.43**	**$ 103.38**	**$ 117.25**
Stranded Asset Cost Scenario Adder	**(2016$ / MWh)**	**$ -**	**$ 3.81**	**$ 3.81**	**$ -**
Total Energy Cost Including Stranded Asset Cost	**(2016$ / MWh)**	**$ 70.89**	**$ 104.24**	**$ 107.19**	**$ 117.25**
High Environmental Cost Scenario Adder	**(2016$ / MWh)**	**$ 3.66**	**$ -**	**$ -**	**$ -**
Total Energy Cost Including High Environmental Cost	**(2016$ / MWh)**	**$ 74.56**	**$ 100.43**	**$ 103.38**	**$ 117.25**

Based on the results of the base case Analysis presented above, BSP with AQCS is the most economically attractive alternative under the base case assumptions. The second most attractive alternative is the CCGT + Wind option, however, this option results in a 42 percent higher cost of energy than BSP with AQCS. Adding in the stranded asset costs to the CCGT + Wind option increases the differential in cost of energy between these two options to 47 percent. Adding in the high environmental cost scenario adder reduces these differentials in levelized energy costs to 35 percent and 40 percent respectively.

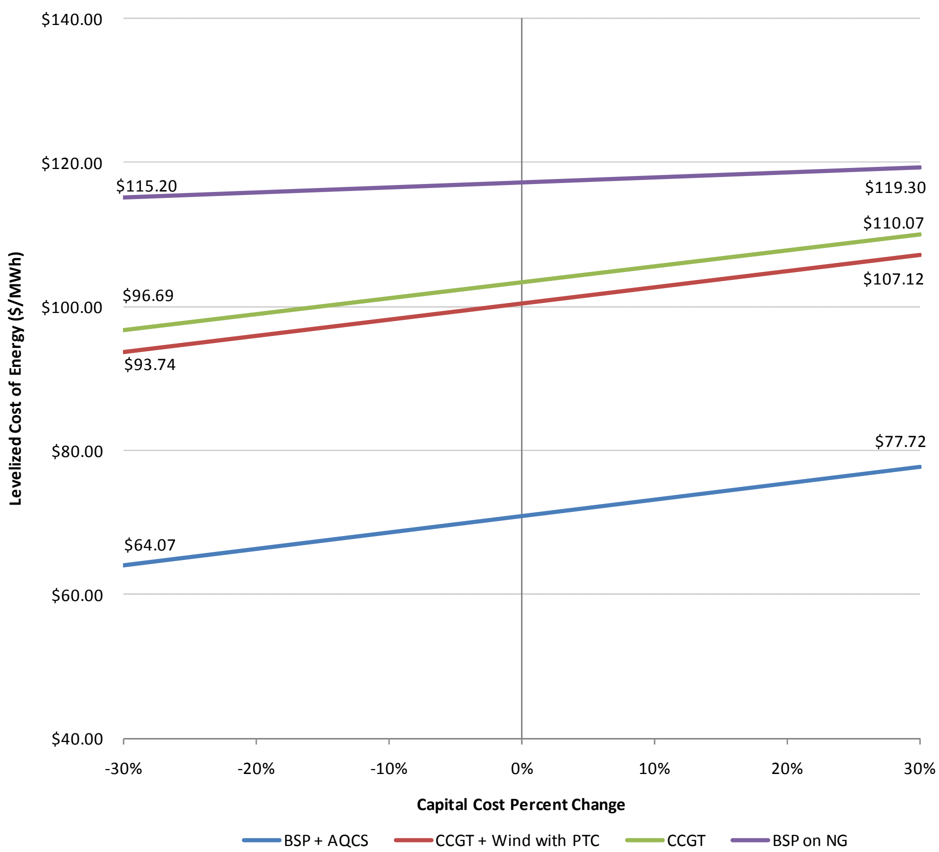
Sensitivity Analysis

A sensitivity analysis was prepared for each of the alternatives evaluated in the Analysis under the following cases:

- Capital Cost (plus or minus 30%)
- Fuel Cost (plus or minus 20%)
- O&M Costs (plus or minus 20%)

A sensitivity analysis was performed to determine the impact of changes to the capital costs of each option. The results of the capital cost sensitivity analysis are presented in Figure 1 below.

Figure 1 – Capital Cost Sensitivity Levelized Energy Costs

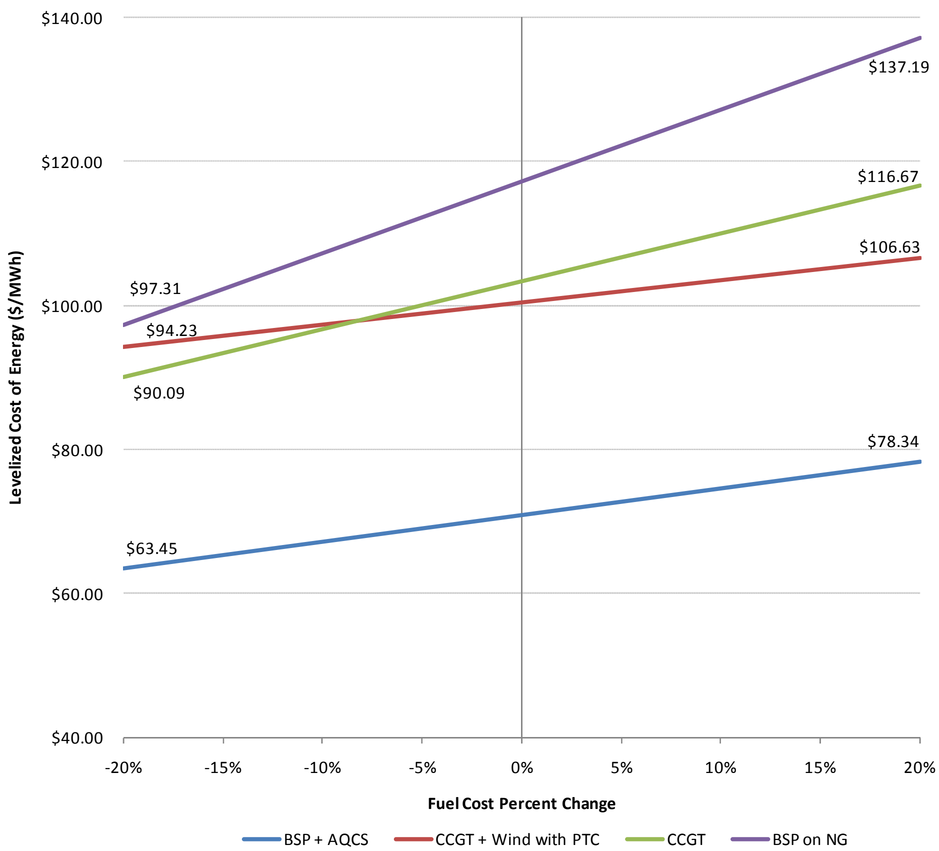


Over the range of capital costs evaluated in this sensitivity analysis, the BSP with AQCS option is preferred in all instances. Capital cost changes have a similar impact on BSP with AQCS, CCGT and CCGT + Wind options, since they all have relatively similar capital costs. Capital cost changes have the least impact on the BSP on NG option, since it requires the least capital cost investment.

A sensitivity analysis was performed to determine the impact of changes to the fuel costs for each option. The results of the fuel cost sensitivity analysis are presented in Figure 2 below.

Mr. Mark Rolfes
Otter Tail Power Corporation
September 19, 2011
Page 9

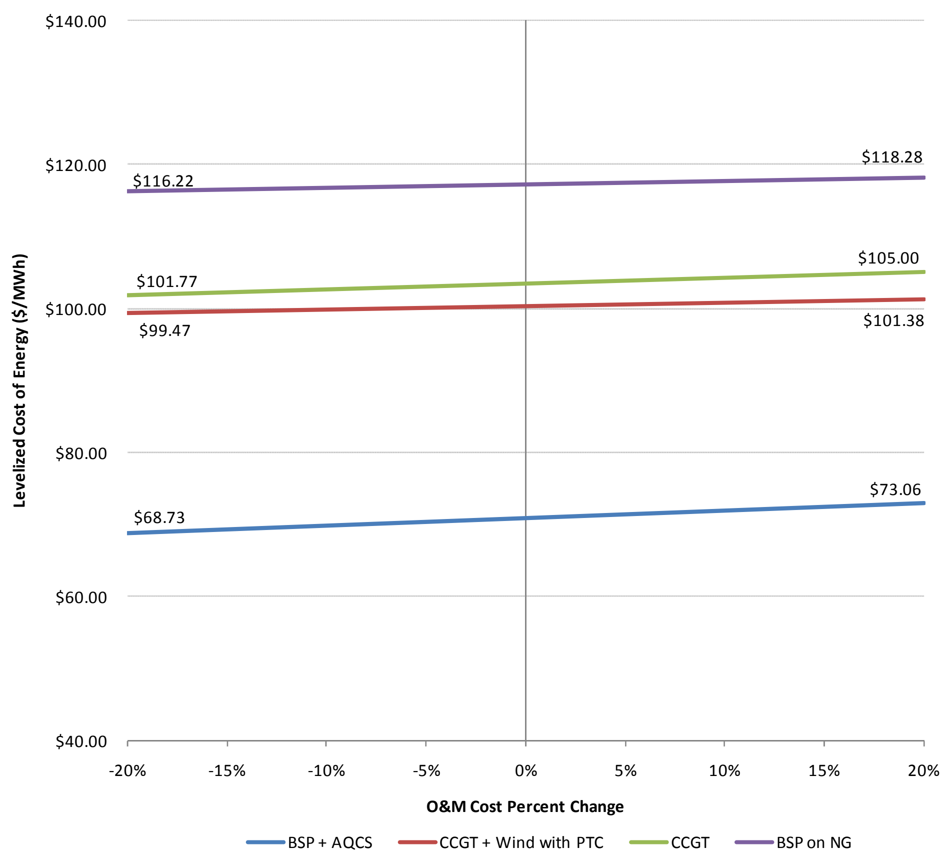
Figure 2 – Fuel Cost Sensitivity Levelized Energy Costs



Over the range of fuel costs evaluated in this sensitivity analysis, the BSP with AQCS option is preferred in all instances. Fuel cost changes have the largest impact on the natural gas-fired options, since natural gas has a much higher base case cost than coal. The impact or fuel cost changes is reduced on the CCGT + Wind case, since more than half of the energy in that case is provided from wind power generation, which is unaffected by changes in fuel prices.

A sensitivity analysis was performed to determine the impact of changes in O&M costs for each of the options. The results of the O&M cost sensitivity analysis are presented in Figure 3 below.

Figure 3 – O&M Cost Sensitivity Levelized Energy Costs



Over the range of O&M costs evaluated in this sensitivity analysis, the BSP with AQCS option is preferred in all instances. O&M cost changes have relatively insignificant impacts on all of the options considered.

Conclusions

Based on the results of this Analysis, the BSP with AQCS is the most economically attractive alternative of the options considered for BSP under the potential future scenarios evaluated. The BSP with AQCS option results in a significantly lower levelized cost of energy than the other options evaluated under the base case assumptions. BSP with AQCS option remains economically attractive relative to the other options considered over the range of sensitivities evaluated in this Analysis.

The impact on other Otter Tail resources and Otter Tail's integrated resource plan (IRP) was not evaluated in this Analysis. Otter Tail will need to determine how a change of resource type at the BSP site would impact other resources in Otter Tail's generation portfolio, as well as how a new resource would fit into Otter Tail's IRP.

If you have any questions regarding the results of this Analysis, please call Jeff Greig at 816-822-3392 or Jeff Kopp at 816-822-4239 to discuss.

Sincerely,

Jeff Greig
General Manager, Business & Technology Services

Jeffrey T Kopp

Jeff Kopp, PE
Development Engineer

JTK

cc: Mark Rolfes

II. Joint Exhibit 2 - REASONABLENESS OF BIG STONE AQCS PROJECT

The South Dakota DENR is the state agency responsible for implementing federal CAA requirements to reduce emissions that may contribute to regional haze from emitting facilities located in South Dakota, including the Big Stone Plant. After conducting a thorough analysis of pollution control options, the DENR determined that the control technologies in the AQCS Project must be required. As a result, the Big Stone Plant Co-Owners must design, construct, install and operate the AQCS by the compliance deadline established by the DENR, or the Plant will not be able to continue operation.

OTP, on behalf of the Co-Owners, has prepared an assessment of alternative scenarios that may be available to respond to the anticipated environmental regulations.[28] OTP developed four response scenarios and evaluated the comparative costs under each scenario using a 20-year levelized cost analysis:

1. Implementing the Big Stone AQCS Project, as Co-Owners have proposed;
2. Repowering Big Stone boiler with natural gas;
3. Retiring/Replacing Big Stone with a CCGT Plant; and
4. Retiring/Replacing Big Stone with a CCGT Plant and purchased wind power.

As shown in Table 2, the AQCS Project is the most economical scenario under all analyses in the Base Case.[29] The analysis of these alternative scenarios was carried out for a Base Case, which also considered the anticipated environmental costs for mercury control and coal ash disposal, as well as the cost of the stranded asset if one of the retirement/replacement options were to be implemented. Table 2 below presents a comparison of the alternative scenarios under the Base Case analysis, including an analysis that incorporates the cost to cover the stranded asset costs ("Stranded Asset Cost Scenario"), and an analysis that includes an additional $5 million in capital cost and $2 million in annual O & M cost for mercury removal and $6.66 million in annual O & M cost for handling coal ash if it is characterized as a hazardous waste ("High Environmental Cost Scenario").

Table 2 – Estimated Levelized Energy Cost (2016$/MWh)

	Big Stone + AQCS	**CCGT + Wind**	**CCGT**	**Big Stone with Natural Gas**
Combined Levelized Energy Cost - (Base Case)	$~~74.38~~70.89	$100.43	$103.38	$117.25
Total Energy Cost Including	$~~74.38~~70.89	$104.24	$107.19	$117.25

[28] Response scenarios that would not be available in the required timeframe, or could not replace the characteristics that Big Stone provides were not further analyzed. The selection of response scenarios that may be viable is fully explained in Joint Exhibit 3.

[29] Attachment 9 (Big Stone Pro Forma Economic Analysis) at 5-6.

Stranded Asset Cost				
Total Energy Cost Including High Environmental Costs	$~~78.04~~74.56	$100.43	$103.38	$117.25

The Base Case analysis comparing installation of the AQCS with various options for repowering or retiring and replacing the Plant with natural gas shows that the AQCS is the most cost-effective option, with the cost of the other options at least $29~~26~~ per MWh or 41~~35~~% higher than the levelized MWh cost of the proposed AQCS.[30] The AQCS remains the most cost-effective option under several sensitivity analyses concerning capital cost (+/-30%), fuel cost (+/-20%), and O & M cost (+/-20%).

[30] Attachment 9 at 6.

II. Joint Exhibit 2 - REASONABLENESS OF BIG STONE AQCS PROJECT

The South Dakota DENR is the state agency responsible for implementing federal CAA requirements to reduce emissions that may contribute to regional haze from emitting facilities located in South Dakota, including the Big Stone Plant. After conducting a thorough analysis of pollution control options, the DENR determined that the control technologies in the AQCS Project must be required. As a result, the Big Stone Plant Co-Owners must design, construct, install and operate the AQCS by the compliance deadline established by the DENR, or the Plant will not be able to continue operation.

OTP, on behalf of the Co-Owners, has prepared an assessment of alternative scenarios that may be available to respond to the anticipated environmental regulations.[28] OTP developed four response scenarios and evaluated the comparative costs under each scenario using a 20-year levelized cost analysis:

1. Implementing the Big Stone AQCS Project, as Co-Owners have proposed;
2. Repowering Big Stone boiler with natural gas;
3. Retiring/Replacing Big Stone with a CCGT Plant; and
4. Retiring/Replacing Big Stone with a CCGT Plant and purchased wind power.

As shown in Table 2, the AQCS Project is the most economical scenario under all analyses in the Base Case.[29] The analysis of these alternative scenarios was carried out for a Base Case, which also considered the anticipated environmental costs for mercury control and coal ash disposal, as well as the cost of the stranded asset if one of the retirement/replacement options were to be implemented. Table 2 below presents a comparison of the alternative scenarios under the Base Case analysis, including an analysis that incorporates the cost to cover the stranded asset costs ("Stranded Asset Cost Scenario"), and an analysis that includes an additional $5 million in capital cost and $2 million in annual O & M cost for mercury removal and $6.66 million in annual O & M cost for handling coal ash if it is characterized as a hazardous waste ("High Environmental Cost Scenario").

Table 2 – Estimated Levelized Energy Cost (2016$/MWh)

	Big Stone + AQCS	CCGT + Wind	CCGT	Big Stone with Natural Gas
Combined Levelized Energy Cost - (Base Case)	$70.89	$100.43	$103.38	$117.25
Total Energy Cost Including	$70.89	$104.24	$107.19	$117.25

[28] Response scenarios that would not be available in the required timeframe, or could not replace the characteristics that Big Stone provides were not further analyzed. The selection of response scenarios that may be viable is fully explained in Joint Exhibit 3.

[29] Attachment 9 (Big Stone Pro Forma Economic Analysis) at 5-6.

Stranded Asset Cost				
Total Energy Cost Including High Environmental Costs	$74.56	$100.43	$103.38	$117.25

The Base Case analysis comparing installation of the AQCS with various options for repowering or retiring and replacing the Plant with natural gas shows that the AQCS is the most cost-effective option, with the cost of the other options at least $29 per MWh or 41% higher than the levelized MWh cost of the proposed AQCS.[30] The AQCS remains the most cost-effective option under several sensitivity analyses concerning capital cost (+/-30%), fuel cost (+/-20%), and O & M cost (+/-20%).

[30] Attachment 9 at 6.

III. Joint Exhibit 3 - ASSESSMENT OF FINANCIAL AND OPERATIONAL IMPACTS OF PENDING ENVIRONMENTAL REGULATIONS TO THE BIG STONE PLANT

The Co-Owners provide this assessment of the financial and operational impacts of pending environmental regulations, including the SD Haze SIP, to the Big Stone Plant. The assessment covers the installation of the pollution controls that comprise the proposed AQCS, as well as other regulatory response scenarios that may be reasonable in view of the costs to comply with the SD Haze SIP, including the retirement or repowering of the Big Stone Plant with natural gas.

By installing the AQCS, the Co-Owners customers will continue to receive the benefits of low-cost, reliable electric power from an existing baseload resource, without the need for development of either a greenfield site or new transmission. In addition, as a baseload resource that is frequently used for load following, the Big Stone Plant is a critical resource for a system that is becoming more dependent on wind power and other variable resources. As this Assessment shows, the continued operation of the Big Stone Plant with the addition of the AQCS is a cost effective means to the meet the future needs of the Co-Owners' customers when taking into the account the costs required to comply with the SD Haze SIP and other pending environmental regulations and other viable regulatory response scenarios. The cost estimates and analysis provided in this Assessment were prepared by OTP, on behalf of the Co-Owners with assistance from the engineering firms of Sargent & Lundy and Burns & McDonnell.

A. FINANCIAL AND OPERATIONAL IMPACTS OF PROPOSED AQCS PROJECT

The SD Haze SIP determined that BART for the Plant is comprised of a separated over fired air system for the Big Stone Plant boiler to reduce the formation of NO_X , an SCR to chemically reduce NO_X into N_2 and H_2O, a Semi-Dry FGD for SO_2 control, and a baghouse for particulate matter control. The AQCS Project would also include all the ductwork, boiler modifications and infrastructure changes needed to support the required equipment. The AQCS Project is necessary to meet the BART requirements of the SD Haze SIP and its implementing regulations. Without installation of the AQCS, the Plant will not be able to comply with the emission limitations that represent BART, and cannot operate after the deadline for BART compliance has passed.[31]

1. Financial Impacts of Proposed AQCS Project

The estimated capital cost for acquisition and installation of the equipment and support systems for the AQCS is approximately $489 million (2015 dollars).[32] This estimate provides an accuracy range of +/- 20% and is the total project cost escalated to its commercial operation date, which is expected to be late in 2015. Montana-Dakota's North Dakota customers will see an approximate 16 percent increase in rates as a result of its share of this total project cost of $78

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[31] *See* ADP Application, Joint Exhibit 1, Section B, Requirement to Implement the Big Stone AQCS Project.

[32] *See* Attachment 5 & ADP Application, Joint Exhibit 1, Section E, Cost Estimate.

million. OTP's North Dakota customers will also see an approximate 16 percent increase in rates as a result of its share of this total project cost of $108 million.

The estimated additional increase in the Plant's operation cost in 2016, the expected first full year of operation, associated with the operation of the AQCS, will be approximately $11 million (including escalation from 2010 dollars).[33] The additional operating expense will increase the cost to produce a MWh of energy by approximately $3.50, or $.0035 per kWh, based on the Plant's net dispatchable energy generation of 3,120,750 MWh. After the AQCS is installed and in operation, the estimated total operating cost for the Plant in 2016 is $27.3 million,[34] with Montana-Dakota's North Dakota share being approximately $4.0 million and OTP's share of approximately $6.0 million. The biggest operational cost increase will be due to the cost of the lime and ammonia necessary to operate the SCR and semi-dry FGD and the addition of employees at the Plant.[35]

Beyond the additional cost to install and operate the AQCS, additional capital and operating costs are likely to be required in response to anticipated regulations for control of mercury emissions and disposal of coal combustion residual (coal ash).[36] The addition of control for mercury, which is likely to be required during the same timeframe as the AQCS Project, is estimated to result in additional capital cost of approximately $5 million[37] and an additional operating cost of approximately $2 million per year.[38] The estimated cost to comply with regulations relating to mercury control will add approximately $0.65 to the cost to produce a MWh of energy, or $.00065 per kWh.

Table 1 contains a summary of the potential anticipated financial impacts of the proposed AQCS, mercury emission standard, and the potential cost of coal ash regulation.

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[33] Attachment 6.

[34] Attachment 6.

[35] Attachment 4, Section 6.

[36]. In addition to the requirements for the AQCS, the Assessment of Financial and Operational Impacts of Pending Environmental Regulations to the Big Stone Plant considered potential cost of new environmental regulations applicable to the Big Stone Plant relating to mercury emission limits and coal ash disposal.

[37] Attachment 5, ACI Estimate.

[38] Attachment 6.

Table 1 – Anticipated Financial Impacts

	Capital Cost (2015$)	Annual O & M Cost (2016$)	Levelized Cost (2016$/MWh)
Big Stone + AQCS	$489 million[39]	$27.3 million[40]	$~~74.38~~70.89[41]
Mercury Control and Coal Ash Disposal[42]	$5 million	$8.7 million	$3.66[43]

2. Operational Impacts of Proposed AQCS Project

Apart from capital and increased operating costs, the installation of the AQCS will not have any significant impacts on the capacity or day-to-day operations of the Big Stone Plant, except for one longer than typical outage in 2015 to connect the AQCS into the Plant once the AQCS systems have been constructed. However, there are certain challenges that are being addressed in the design of the proposed AQCS Project and that have been included in the cost estimates for the AQCS.

First, some modifications need to be made to the boiler to allow for effective operation of the SCR. The SCR provides effective control of NO_X emissions, but it operates well only within a specified temperature range.[44] The boiler temperatures must be maintained so they are neither too hot at full load nor too cold at low loads. To ensure that proper temperatures are maintained, the Plant's boiler will need to be modified.[45] The boiler efficiency is expected to improve as a result of the modifications, and the hourly boiler heat input will not increase above the current permitted levels.

The design of the AQCS equipment must also allow the Plant to maintain its current ability to follow load. Varying load conditions must be taken into account in the design of the semi-dry FGD and SCR. Currently, the Plant will run in a load following arrangement for much of the

39 Attachment 5.

40 Attachment 6.

41 Attachment 9 at 6, Table 2.

42 The addition of mercury control equipment is estimated to cost approximately $5 million, Attachment 5, ACI Estimate, and the annual O & M cost for the mercury control equipment is estimated to be $2 million, Attachment 6. The increased costs for disposal of coal ash could be as high as approximately $6.7 million per year, based on a $37.50 per ton estimate for disposal, including both capital and operating costs. Section IV; *Special Reliability Assessment: Resource Adequacy Impact of Potential U.S. Environmental Regulations*, at 57, NERC (October 2010).

43 Attachment 9 at 5-6.

44 Attachment 4 at 3-4.

45 Attachment 4, Section 3.2, describes boiler modifications that are anticipated to be needed as a result of the AQCS Project.

spring and fall. For example, on a typical spring day when the demand for electricity is relatively low, the Plant is likely to see minimum load at night, but as the electrical load starts increasing, the output of the Plant will rise until it reaches full load during the peak load periods, and then drop off as the electric load drops off at night, eventually getting back to the minimum load for a few hours before repeating the cycle. The design of the AQCS equipment will assure that the ability of the Plant to follow load is not compromised and that the AQCS Project does not decrease the range of load at which the unit may efficiently and safely operate. For example, the AQCS Project will be designed to minimize the duct distance between the semi-dry FGD and the baghouse to limit the amount of ash depositing in the duct work at low loads. Other design considerations involve ensuring that proper temperatures are maintained and that equipment is the appropriate size to operate at both low and full loads.[46]

Other operational impacts of the AQCS Project will include the addition of employees to operate and maintain the Plant with the additional equipment.[47] OTP will provide training on operation of the new equipment to the new employees. Additionally, operation of Big Stone following installation of the AQCS will produce a greater volume of ash to be disposed of because the addition of the semi-dry FGD will result in ash that is less dense than the ash currently produced by the Plant. OTP has sufficient capacity in its existing disposal site for this ash.[48]

B. ALTERNATIVE RESPONSE SCENARIOS

1. Selection of Alternative Response Scenarios

OTP, on behalf of the Co-Owners has focused on the identification of alternative scenarios that involve either the retirement and replacement or the repowering of the Big Stone Plant. In view of the specific requirements set out in the SD Haze SIP and its implementing regulations, there is only one response scenario that involves the installation of pollution control equipment and that scenario is the proposed AQCS Project. In addition, the use of pollution allowances is not a viable compliance approach because there are no pollution trading programs available that can substitute for BART compliance and address the underlying regulatory concern for visibility in Class I areas.[49]

OTP, on behalf of the Co-Owners, assessed the current status of Greenhouse Gas Regulatory requirements when considering alternatives. Congress has considered, but has not adopted, legislation which would require a reduction in Greenhouse Gas (GHG) emissions. However,

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[46] Attachment 4 at 2-5.

[47] Attachment 4 at 6-1.

[48] *Id.* at 3-22.

[49] Emission trading of SO_2 and NO_x may have limited potential to be an option for plants located in the Transport Rule's control zone, subject to affected state decisions in their regional haze SIPs, but South Dakota is not a state proposed for inclusion under that rule. Emission trading of SO_2 under the Acid Deposition Program is in addition to, and does not affect the requirement to comply with other CAA program requirements, such as the regional haze program. 42 U.S.C. § 7651b(f) (CAA § 403(f)).

there is no legislation under active consideration at this time. The EPA is proceeding to regulate GHGs under a number of provisions of the Clean Air Act beginning with regulation under the Prevention of Significant Deterioration (PSD) and the Title V permitting process in January 2011. OTP does not anticipate making modifications at Big Stone as part of the AQCS project that would trigger PSD requirements, including for GHGs. Consequently, GHG emissions are not projected to trigger the need for a PSD permit as a result of the AQCS Project.

EPA has announced a timeframe for developing New Source Performance Standards (NSPS) for GHGs from electric generating units. EPA plans to propose this NSPS in August 2011, and adopt the standard in June 2012. In general, NSPS become applicable to new sources built after the effective date of the regulation, or affect what may be required to be included as an emission control at the time an existing source makes a change significant enough to trigger NSPS applicability. To trigger the applicability of NSPS, an existing source must make a modification that increases its maximum hourly emissions rate. The Co-Owners do not anticipate making a modification at Big Stone Plant that would trigger NSPS requirements. The Big Stone AQCS Project is not projected to trigger the applicability of the NSPS for GHGs that EPA plans to develop.

At the same time EPA develops the NSPS, EPA also plans to issue emission guidelines for existing sources under CAA Section 111(d) (111(d) Standard). A 111(d) Standard, unlike the NSPS, applies to an existing source. States are given a period of time to develop plans to implement a 111(d) Standard, and if a state does not develop such a plan, EPA will prescribe a plan for that state.

While the potential impact of a 111(d) standard on Big Stone is not yet known, standards of performance for GHGs, especially for existing sources, are anticipated to focus on efficiency improvements rather than add-on controls. The Co-Owners have in the past implemented efficiency measures at Big Stone through installation of a more efficient steam turbine at the Plant. The capital cost of efficiency improvements could be offset in whole or in part by reduced fuel costs.

To identify potentially viable alternatives for economic evaluation, OTP, on behalf of the Co-Owners first identified the needs currently served by the Big Stone Plant, as well as the basic operating characteristics of the Plant. The Big Stone Plant is a key baseload asset for its three utility Co-Owners, serving the existing load of customers in several states. The Plant is the largest baseload resource for each of the Co-Owners. Given the critical resource role played by the Big Stone Plant, OTP, on behalf of the Co-Owners developed alternatives that were capable of reliably: (1) producing approximately 3 million megawatt-hours of electricity per year; (2) serving as a baseload resource, with the ability to follow load and be a dispatchable resource with high availability; and (3) being in operation prior to expiration of the deadline for Big Stone to comply with the BART requirement. Analysis performed by the Midwest Independent Transmission System Operator ("MISO") has assumed the presence of a baseload generation source at the Big Stone site, and any change in location would require a reevaluation of the transmission system.

Given the significant customer load served by the Big Stone Plant, the Co-Owners identified coal, hydropower, nuclear and natural gas as practical potential replacement options that could

meet the above criteria.[50] Since the proposed AQCS Project includes continuation of coal generation at the Plant, another coal option was not considered as an alternative response scenario. Hydropower and new nuclear generation were rejected because expected permitting difficulties suggest that these resources could not be available in the timeframe required for compliance with the SD Haze SIP and its implementing rules and because the size of these alternatives to be economic, would exceed the needs of the Co-Owners. Based on these considerations, it was determined that natural gas was the only viable retirement/replacement or repowering option that could potentially replace the current functions of the Big Stone Plant in the required timeframe.

With respect to natural gas, three different scenarios were assessed:

1) Converting the existing Big Stone boiler to natural gas combustion;
2) Constructing a new gas-fired combined-cycle turbine at the Big Stone site, abandoning the existing equipment at the Plant; and
3) Combining a new gas combined-cycle turbine at the Big Stone site with wind generation.

Due to the timing of the compliance requirement for operation of the AQCS under the SD Haze SIP, it is unlikely that any of these three natural gas scenarios could be engineered, designed, permitted, procured, and constructed in the same timeframe as the Big Stone AQCS Project. Consequently, there would like be a minimum period of one to three additional years between the retirement of the current Big Stone Plant and the availability of these new resources, during which time OTP, NorthWestern Energy and Montana-Dakota would be dependent on the market or contracted purchases to meet the needs of their customers for the three million MWh per year currently provided by Big Stone. Assessment of the natural gas scenarios are provided below.

Other repowering scenarios were considered and ultimately rejected as infeasible, including one scenario involving repowering the existing generating unit with biomass. Biomass fuel may be capable of co-firing up to 10% of the heat input of the Plant, but this would not remove the AQCS Project requirement if coal still comprised 90% of the fuel mix. Achieving a 10% level of biomass as fuel would require drawing on most of the available biomass in a 30 to 50-mile radius, with an estimated delivered cost of \$8 to \$9 per million Btus. This is approximately four times higher than the cost of coal and approximately twice that of natural gas. The conversion to biomass fuel is not a viable response scenario because the AQCS Project would still be required, as well as the cost and logistical challenges involved in securing sufficient biomass fuel.[51]

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[50] Conservation and load management were not considered as a feasible alternative response scenario to replace this significant existing baseload facility, as conservation and load management are already assumed to be necessary to meet future resource needs.

[51] The most readily available source of biomass in the area is corn stover. This fuel would likely be delivered in large round bales with 20 to 25 bales per semi-load. At the current firing rate, the Big Stone Plant would need to consume close to ten of these large bales every minute due to the low Btu value, high moisture and low density of the fuel. Thus, biomass co-firing is not a viable regulatory response scenario.

The Co-Owners also rejected as infeasible a scenario involving the construction of a gas-fired combustion turbine and a heat-recovery boiler at the Big Stone site, and the use of that steam generation to power the existing Plant turbine. To implement this type of conversion, approximately two-thirds of the generation would come from the new gas-fired generation and one-third would come from the existing steam turbine. The existing steam turbine at Big Stone produces 475 megawatts. Using the 1/3 to 2/3 ratio, the generation from the Big Stone Plant would be required to increase from 475 megawatts to 1,425 megawatts. This additional generation would overload available transmission, since there are already over 2,000 megawatts in the queue at the Big Stone site for additional transmission, and thus could not be available before the AQCS Project's compliance deadline. In addition, this scenario would generate roughly 1,000 megawatts of additional intermediate load generation that is unlikely to fit the needs of the current Big Stone Co-Owners. Due to the time delay, the mismatch of resources and the high cost for such a sizeable gas plant, this response scenario was not further evaluated.

2. Comparative Analysis of the Financial Impacts of Proposed AQCS Project and Alternative Regulatory Response Scenarios

To assess financial impacts, the Co-Owners retained the engineering firm of Burns & McDonnell to perform a pro forma economic analysis to calculate the levelized costs of power for the AQCS Project and the alternative response scenarios.[52]

To simplify the analysis, Burns & McDonnell assumed that all response scenarios would be available by January 1, 2016. This assumption favors the alternative scenarios because the Burns & McDonnell analysis does not include any allowance to cover the need to purchase energy from the market during the period, very likely to run at least one to three years (2016 to 2018), between the retirement of Big Stone and the commercial operation of the natural gas scenarios.[53]

To perform its analysis, Burns & McDonnell, as much as possible, used the same modeling inputs as provided by OTP in its most recently filed Minnesota Integrated Resource Plan ("IRP") in Minnesota Docket No. E017/RP-10-623. Courtesy copies were filed with the North Dakota Public Service Commission in late June of 2010. When the necessary inputs for this ADP analysis were not available in the IRP filing, Burns & McDonnell's assumptions were based upon either the analyses prepared by Sargent & Lundy for OTP or the recent project experience of Burns & McDonnell, including its work on projects involving more than 25 gigawatts of gas-fired generation in the last ten years.[54] Montana-Dakota reviewed the assumptions provided by OTP and agrees that the Burns & McDonnell analyses reasonably represent alternatives available to Montana-Dakota.

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52 The Burns & McDonnell analysis is provided in Attachment 9.

53 OTP has estimated that the likely cost to enter into a Power Purchase Agreement ("PPA") to meet customer needs during the lag period would be between \$87 million and \$262 million. This estimate assumed the lowest cost option would be a coal PPA.

54 The Sargent & Lundy analyses are provided in Attachments 5, 6, and 8.

Burns & McDonnell's analysis covers a 20-year period of operation (which provides a reasonable time period for cost recovery and is within the useful life of the equipment being added and the existing plant) and levelizes construction and operation (including fuel) costs into a levelized cost per Megawatt Hour (MWh). In addition to considering a Base Case analysis, Burns & McDonnell also calculated energy costs if stranded asset costs were included in the repowering and retirement/replacement scenarios and if additional costs for environmental controls for mercury and coal ash were included in the AQCS scenario.

a. Base Case Analysis

As provided in Joint Exhibit 2, Burns & McDonnell analysis found the AQCS Project the most economical scenario by a substantial margin.[55] Under the Base Case scenario, the AQCS Project is the lowest cost option by ~~35~~41% over the next lowest cost option, the combined cycle plus wind. Adding the stranded asset cost to the combined cycle plus wind option increases this differential in the cost of energy between these two options to ~~40~~47%, while adding the high environmental costs to the AQCS reduces the cost differential to ~~29~~35%.[56]

Table 2 below (also presented in Joint Exhibit 2) provides the results of the Burns & McDonnell analysis. The estimated cost for each scenario in the Base Case analysis is provided in the horizontal row identified as "Combined Levelized Energy Cost." The estimated levelized energy costs if stranded asset costs are included for the repowering and retirement/replacement scenarios is provided in the horizontal row "Stranded Asset Cost Scenario." And, the estimated levelized energy costs if additional costs for environmental controls for mercury and coal ash disposal are included in the AQCS option is provided in the row marked as "High Environmental Cost Scenario."[57]

55 Attachment 9 at 6-12.

56 Attachment 9 at 6-7.

57 Under the High Environmental Cost Scenario, Burns & McDonnell assumed an additional $5 million in capital cost and $2 million in O & M cost for mercury emission control and an additional $6.66 million for handling coal ash if it is characterized as a special waste under the RCRA hazardous waste rules. Attachment 9 at 6.

Table 2 – Estimated Levelized Energy Cost (2016$/MWh)[58]

	Big Stone + AQCS	CCGT + Wind	CCGT	Big Stone with Natural Gas
Combined Levelized Energy Cost – (Base Case)	$~~74.38~~70.89	$100.43	$103.38	$117.25
Total Energy Cost Including Stranded Asset Cost	$~~74.38~~70.89	$104.24	$107.19	$117.25
Total Energy Cost Including High Environmental Costs	$~~78.04~~74.56	$100.43	$103.38	$117.25

b. Sensitivity Analyses

In addition to the Base Case analysis, Burns & McDonnell prepared three sensitivity analyses to assess the effects of capital cost variations, fuel cost variations and operational cost variations.

(1) Capital Cost Sensitivity Analysis

In this analysis, Burns & McDonnell ran a sensitivity case to consider the effect of a range of capital costs (plus or minus 30%). In all cases, the AQCS Project was the low cost scenario and by a substantial margin. For the low end of the range for capital costs (minus 30%), levelized costs of energy for the AQCS Project were estimated to be $~~66.24~~64.07 MWh compared to $~~90.09~~93.74 MWh for the next least cost scenario (combined cycle and wind). For the high end of the range for capital costs (plus 30%), the levelized energy cost for the AQCS Project was $~~82.51~~77.72 MWh compared to $~~106.63~~107.12 MWh for the next lowest cost option (combined cycle wind).[59]

(2) Fuel Cost Sensitivity Analysis

In this analysis, Burns & McDonnell ran a sensitivity analysis to determine the impact of changes to the fuel costs for each option. The analysis considered the effect of a range of fuel costs (plus or minus 20%). Over the range of fuel costs evaluated, the AQCS Project was preferred in all instances. For the low end of the range of fuel costs (minus 20%), levelized costs of energy for the AQCS Project were estimated to be $~~66.24~~63.45 MWh compared to $90.09 MWh for the next least cost scenario (combined cycle). For the high end of the range for capital costs (plus 20%), the levelized energy cost for the AQCS Project was $~~82.51~~78.34 MWh compared to $106.63 MWh for the next lowest cost option (combined cycle wind).[60]

(3) O & M Sensitivity Analysis

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58 Attachment 9 at 6, Table 2.

59 Attachment 9 at 8, Figure 1.

60 Attachment 9 at 9, Figure 2.

A sensitivity analysis was performed to determine the impact of changes in O & M costs (plus or minus 20%). The AQCS Project was the preferred option over the range of costs evaluated. In all cases, the AQCS Project was the low cost scenario and by a substantial margin. For the low end of the range for O & M costs (minus 20%), levelized costs of energy for the AQCS Project were estimated to be $~~72.21~~68.73 MWh compared to $99.47 MWh for the next least cost scenario (combined cycle and wind). For the high end of the range for capital costs (plus 20%), the levelized energy cost for the AQCS Project was $~~76.54~~73.06 MWh compared to $101.38 MWh for the next lowest cost option (combined cycle wind).[61]

3. Comparative Analysis of the Operational Impacts of Proposed AQCS Project and Alternative Regulatory Response Scenarios

The financial analysis makes a comparison between the Big Stone AQCS Project and other regulatory response scenarios based on having response scenarios fully capable of replacing the capacity, energy output and dispatchable qualities provided by the Big Stone Plant. There are, however, additional operational differences that are likely to occur between the Big Stone AQCS and implementation of any of the natural gas-based regulatory response scenarios.

a. Operational Issues for All Natural Gas Response Scenarios

All three natural gas scenarios will impose significantly higher costs per MWh of electricity produced than would the AQCS Project. This in turn means that while the natural gas response scenarios are *capable* of replacing the Big Stone Plant's capacity and energy output, they are likely to be run at significantly lower capacity factors, requiring more frequent access to the market for energy purchases. As a result, significant amounts of power would be purchased at prices lower than the natural gas scenarios, but considerably higher than the energy cost of Big Stone after installation of the AQCS.

For example, an energy purchase of $95/MWh in the Base Case analysis would be economical compared to the natural gas scenarios, but would be $22/MWh more expensive than power that could be produced by Big Stone with the AQCS Project. To the extent that market price at any given time does not support the operation of natural gas plants, this power is likely to be produced through other means, including by coal-fired power plants.[62] And in situations where less power is available on the market, the natural gas scenarios would need to be employed, at substantial additional cost to the utilities' customers.

The market price/operating cost dynamics that will lower the capacity factors for the natural gas response scenarios also reduce their usefulness for load following wind resources. A high

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[61] Attachment 9 at 10, Figure 3.

[62] The AQCS Project will significantly reduce SO_2 and NO_x emissions from the Plant, while maintaining current high control of particulate matter. In addition, mercury control is planned to target a 90% emission reduction, implemented at the same time as the AQCS. In general, the natural gas options are expected to require installation of NO_x control, but have little emissions of the other pollutants. The extent to which natural gas scenarios would result in less emissions of these pollutants would depend on what the source is for power purchased on the market to fill in for the expected lower capacity factor of the natural gas scenarios.

capacity factor baseload resource such as the current Big Stone Plant (and the Big Stone Plant with AQCS) is running many more hours of the year (for example, 85% of the time compared to 50% or less of the time), allowing its power output to be increased and decreased quickly in a load following function without the need for a full start up or shut down of the unit.

Deploying any of the natural gas scenarios thus includes dramatically increasing the exposure of the utilities' customers to the market price of power and to fluctuations in the price of natural gas, while reducing the load following capability of the Plant. The next sections assess operational impacts that are individual to each regulatory response scenario.

b. Repowering the Big Stone Plant with Natural Gas

Repowering the Big Stone Plant's boiler to burn natural gas is the highest cost option in the Base Case and among the various sensitivity analyses. Repowering would be less efficient than a new CCGT, which is illustrated by the substantially higher fuel cost in the Base Case ($99.70/MWh), compared with the other natural gas response scenarios ($66.44/MWh). The high operating cost of the repowered unit would likely result in limited use of the Plant.[63] As a result, the repowering scenario would expose customers to both additional market purchases and more expensive market purchases than the other natural gas scenarios.

A repowered unit would take approximately two days to start up and shut down, considerably longer than a new CCGT. High market prices would therefore need to be predicted for a long period of time to justify start up of a repowered unit. In addition, this start up time, combined with a limited use profile, would make a repowered unit unable to effectively load follow wind energy resources on the utilities' electric systems.

c. Retirement and Replacement with Natural Gas Combined Cycle Plant

Replacement of the Big Stone Plant with a new natural gas combined cycle unit at the Big Stone site was evaluated in two scenarios: CCGT and CCGT/Wind Power Purchases. Both scenarios are significantly higher cost in the Base Case, as well as in all sensitivity analyses.

Operationally, the CCGT scenario would allow a faster start up and shut down time than the repowering scenario. CCGTs would start up or shut down in 3-5 hours, substantially slower than a peaking unit such as a Simple Cycle Gas Turbine, which can start up in 10 minutes.[64] Due to its cost of power per MWh, however, a CCGT would likely have an intermediate, rather than a baseload, capacity factor of about 30 to 50%. This would make it less desirable for load following because it would have many more hours during the year when it is not operating at all. Load following would therefore require more start ups and shut downs than for a baseload plant,

[63] The repowered unit would be expected to have the highest cost per MWh, despite its relatively lower capital cost ($267 million) than the other natural gas response scenarios ($621.29 million), because its lower efficiency increases its fuel cost per MWh of power produced. *See* Attachment 9 at 6, Table 2.

[64] A Simple Cycle Gas Turbine ("SCGT") is not a viable alternative response scenario, because it cannot replace the Big Stone Plant as a baseload resource.

increasing the O & M costs for the unit. When a CCGT unit is running, however, it would be capable of increasing or decreasing its output to follow load.

The CCGT and CCGT/Wind Power Purchases scenarios have similar costs per MWh through the different sensitivity analyses, with the CCGT slightly more expensive except in the case of a drop in the price of natural gas of 10% or more. The capital cost of the CCGT scenarios, \$621,289,115 (2016\$), is about 27% higher than the capital cost of the Big Stone AQCS Project.

C. CONCLUSION

The financial analysis demonstrates that the Big Stone AQCS is the most economic scenario in the Base Case, and in the Base Case with an increase for Stranded Asset Costs and for anticipated environmental costs ("High Environmental Cost"). The Base Case analysis comparing installation of the AQCS with various options for repowering or retiring and replacing the Plant with natural gas shows that the AQCS is the most cost-effective option, with the cost of the other options ~~35~~41% or more higher than the levelized MWh cost of the proposed AQCS. The AQCS remains the most cost-effective option under several sensitivity analyses concerning capital cost (+/-30%), fuel cost (+/-20%) and O & M cost (+/-20%).

Under multiple scenarios that consider potential changes in capital, O & M and fuel costs, the Big Stone AQCS remains the least cost option. This conclusion does not change when considering the potential for additional costs that may be imposed by anticipated environmental regulation. Repowering is the highest cost natural gas scenario, with the worst load following capability. Retirement of the Plant and replacement with a CCGT has a significantly higher capital cost than the Big Stone AQCS.

Implementation of any of the natural gas response scenarios instead of the Big Stone AQCS would unreasonably expose North Dakota customers to significantly higher costs under a wide range of potential future conditions. In addition, deploying any of the natural gas scenarios dramatically increases the exposure of North Dakota customers to the market price of power and to fluctuations in the price of natural gas, while reducing the load following capability of the Plant.

The assessment of the financial and operational inputs of the anticipated regulations to the Big Stone Plant demonstrates that the proposed AQCS Project is reasonable and prudent.

III. Joint Exhibit 3 - ASSESSMENT OF FINANCIAL AND OPERATIONAL IMPACTS OF PENDING ENVIRONMENTAL REGULATIONS TO THE BIG STONE PLANT

The Co-Owners provide this assessment of the financial and operational impacts of pending environmental regulations, including the SD Haze SIP, to the Big Stone Plant. The assessment covers the installation of the pollution controls that comprise the proposed AQCS, as well as other regulatory response scenarios that may be reasonable in view of the costs to comply with the SD Haze SIP, including the retirement or repowering of the Big Stone Plant with natural gas.

By installing the AQCS, the Co-Owners customers will continue to receive the benefits of low-cost, reliable electric power from an existing baseload resource, without the need for development of either a greenfield site or new transmission. In addition, as a baseload resource that is frequently used for load following, the Big Stone Plant is a critical resource for a system that is becoming more dependent on wind power and other variable resources. As this Assessment shows, the continued operation of the Big Stone Plant with the addition of the AQCS is a cost effective means to the meet the future needs of the Co-Owners' customers when taking into the account the costs required to comply with the SD Haze SIP and other pending environmental regulations and other viable regulatory response scenarios. The cost estimates and analysis provided in this Assessment were prepared by OTP, on behalf of the Co-Owners with assistance from the engineering firms of Sargent & Lundy and Burns & McDonnell.

A. FINANCIAL AND OPERATIONAL IMPACTS OF PROPOSED AQCS PROJECT

The SD Haze SIP determined that BART for the Plant is comprised of a separated over fired air system for the Big Stone Plant boiler to reduce the formation of NO_X , an SCR to chemically reduce NO_X into N_2 and H_2O, a Semi-Dry FGD for SO_2 control, and a baghouse for particulate matter control. The AQCS Project would also include all the ductwork, boiler modifications and infrastructure changes needed to support the required equipment. The AQCS Project is necessary to meet the BART requirements of the SD Haze SIP and its implementing regulations. Without installation of the AQCS, the Plant will not be able to comply with the emission limitations that represent BART, and cannot operate after the deadline for BART compliance has passed.[31]

1. Financial Impacts of Proposed AQCS Project

The estimated capital cost for acquisition and installation of the equipment and support systems for the AQCS is approximately $489 million (2015 dollars).[32] This estimate provides an accuracy range of +/- 20% and is the total project cost escalated to its commercial operation date, which is expected to be late in 2015. Montana-Dakota's North Dakota customers will see an approximate 16 percent increase in rates as a result of its share of this total project cost of $78

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[31] *See* ADP Application, Joint Exhibit 1, Section B, Requirement to Implement the Big Stone AQCS Project.

[32] *See* Attachment 5 & ADP Application, Joint Exhibit 1, Section E, Cost Estimate.

million. OTP's North Dakota customers will also see an approximate 16 percent increase in rates as a result of its share of this total project cost of $108 million.

The estimated additional increase in the Plant's operation cost in 2016, the expected first full year of operation, associated with the operation of the AQCS, will be approximately $11 million (including escalation from 2010 dollars).[33] The additional operating expense will increase the cost to produce a MWh of energy by approximately $3.50, or $.0035 per kWh, based on the Plant's net dispatchable energy generation of 3,120,750 MWh. After the AQCS is installed and in operation, the estimated total operating cost for the Plant in 2016 is $27.3 million,[34] with Montana-Dakota's North Dakota share being approximately $4.0 million and OTP's share of approximately $6.0 million. The biggest operational cost increase will be due to the cost of the lime and ammonia necessary to operate the SCR and semi-dry FGD and the addition of employees at the Plant.[35]

Beyond the additional cost to install and operate the AQCS, additional capital and operating costs are likely to be required in response to anticipated regulations for control of mercury emissions and disposal of coal combustion residual (coal ash).[36] The addition of control for mercury, which is likely to be required during the same timeframe as the AQCS Project, is estimated to result in additional capital cost of approximately $5 million[37] and an additional operating cost of approximately $2 million per year.[38] The estimated cost to comply with regulations relating to mercury control will add approximately $0.65 to the cost to produce a MWh of energy, or $.00065 per kWh.

Table 1 contains a summary of the potential anticipated financial impacts of the proposed AQCS, mercury emission standard, and the potential cost of coal ash regulation.

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[33] Attachment 6.

[34] Attachment 6.

[35] Attachment 4, Section 6.

[36]. In addition to the requirements for the AQCS, the Assessment of Financial and Operational Impacts of Pending Environmental Regulations to the Big Stone Plant considered potential cost of new environmental regulations applicable to the Big Stone Plant relating to mercury emission limits and coal ash disposal.

[37] Attachment 5, ACI Estimate.

[38] Attachment 6.

Table 1 – Anticipated Financial Impacts

	Capital Cost (2015$)	Annual O & M Cost (2016$)	Levelized Cost (2016$/MWh)
Big Stone + AQCS	$489 million[39]	$27.3 million[40]	$70.89[41]
Mercury Control and Coal Ash Disposal[42]	$5 million	$8.7 million	$3.66[43]

2. Operational Impacts of Proposed AQCS Project

Apart from capital and increased operating costs, the installation of the AQCS will not have any significant impacts on the capacity or day-to-day operations of the Big Stone Plant, except for one longer than typical outage in 2015 to connect the AQCS into the Plant once the AQCS systems have been constructed. However, there are certain challenges that are being addressed in the design of the proposed AQCS Project and that have been included in the cost estimates for the AQCS.

First, some modifications need to be made to the boiler to allow for effective operation of the SCR. The SCR provides effective control of NO_X emissions, but it operates well only within a specified temperature range.[44] The boiler temperatures must be maintained so they are neither too hot at full load nor too cold at low loads. To ensure that proper temperatures are maintained, the Plant's boiler will need to be modified.[45] The boiler efficiency is expected to improve as a result of the modifications, and the hourly boiler heat input will not increase above the current permitted levels.

The design of the AQCS equipment must also allow the Plant to maintain its current ability to follow load. Varying load conditions must be taken into account in the design of the semi-dry FGD and SCR. Currently, the Plant will run in a load following arrangement for much of the

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[39] Attachment 5.

[40] Attachment 6.

[41] Attachment 9 at 6, Table 2.

[42] The addition of mercury control equipment is estimated to cost approximately $5 million, Attachment 5, ACI Estimate, and the annual O & M cost for the mercury control equipment is estimated to be $2 million, Attachment 6. The increased costs for disposal of coal ash could be as high as approximately $6.7 million per year, based on a $37.50 per ton estimate for disposal, including both capital and operating costs. Section IV; *Special Reliability Assessment: Resource Adequacy Impact of Potential U.S. Environmental Regulations*, at 57, NERC (October 2010).

[43] Attachment 9 at 5-6.

[44] Attachment 4 at 3-4.

[45] Attachment 4, Section 3.2, describes boiler modifications that are anticipated to be needed as a result of the AQCS Project.

spring and fall. For example, on a typical spring day when the demand for electricity is relatively low, the Plant is likely to see minimum load at night, but as the electrical load starts increasing, the output of the Plant will rise until it reaches full load during the peak load periods, and then drop off as the electric load drops off at night, eventually getting back to the minimum load for a few hours before repeating the cycle. The design of the AQCS equipment will assure that the ability of the Plant to follow load is not compromised and that the AQCS Project does not decrease the range of load at which the unit may efficiently and safely operate. For example, the AQCS Project will be designed to minimize the duct distance between the semi-dry FGD and the baghouse to limit the amount of ash depositing in the duct work at low loads. Other design considerations involve ensuring that proper temperatures are maintained and that equipment is the appropriate size to operate at both low and full loads.[46]

Other operational impacts of the AQCS Project will include the addition of employees to operate and maintain the Plant with the additional equipment.[47] OTP will provide training on operation of the new equipment to the new employees. Additionally, operation of Big Stone following installation of the AQCS will produce a greater volume of ash to be disposed of because the addition of the semi-dry FGD will result in ash that is less dense than the ash currently produced by the Plant. OTP has sufficient capacity in its existing disposal site for this ash.[48]

B. ALTERNATIVE RESPONSE SCENARIOS

1. Selection of Alternative Response Scenarios

OTP, on behalf of the Co-Owners has focused on the identification of alternative scenarios that involve either the retirement and replacement or the repowering of the Big Stone Plant. In view of the specific requirements set out in the SD Haze SIP and its implementing regulations, there is only one response scenario that involves the installation of pollution control equipment and that scenario is the proposed AQCS Project. In addition, the use of pollution allowances is not a viable compliance approach because there are no pollution trading programs available that can substitute for BART compliance and address the underlying regulatory concern for visibility in Class I areas.[49]

OTP, on behalf of the Co-Owners, assessed the current status of Greenhouse Gas Regulatory requirements when considering alternatives. Congress has considered, but has not adopted, legislation which would require a reduction in Greenhouse Gas (GHG) emissions. However,

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[46] Attachment 4 at 2-5.

[47] Attachment 4 at 6-1.

[48] *Id.* at 3-22.

[49] Emission trading of SO_2 and NO_x may have limited potential to be an option for plants located in the Transport Rule's control zone, subject to affected state decisions in their regional haze SIPs, but South Dakota is not a state proposed for inclusion under that rule. Emission trading of SO_2 under the Acid Deposition Program is in addition to, and does not affect the requirement to comply with other CAA program requirements, such as the regional haze program. 42 U.S.C. § 7651b(f) (CAA § 403(f)).

there is no legislation under active consideration at this time. The EPA is proceeding to regulate GHGs under a number of provisions of the Clean Air Act beginning with regulation under the Prevention of Significant Deterioration (PSD) and the Title V permitting process in January 2011. OTP does not anticipate making modifications at Big Stone as part of the AQCS project that would trigger PSD requirements, including for GHGs. Consequently, GHG emissions are not projected to trigger the need for a PSD permit as a result of the AQCS Project.

EPA has announced a timeframe for developing New Source Performance Standards (NSPS) for GHGs from electric generating units. EPA plans to propose this NSPS in August 2011, and adopt the standard in June 2012. In general, NSPS become applicable to new sources built after the effective date of the regulation, or affect what may be required to be included as an emission control at the time an existing source makes a change significant enough to trigger NSPS applicability. To trigger the applicability of NSPS, an existing source must make a modification that increases its maximum hourly emissions rate. The Co-Owners do not anticipate making a modification at Big Stone Plant that would trigger NSPS requirements. The Big Stone AQCS Project is not projected to trigger the applicability of the NSPS for GHGs that EPA plans to develop.

At the same time EPA develops the NSPS, EPA also plans to issue emission guidelines for existing sources under CAA Section 111(d) (111(d) Standard). A 111(d) Standard, unlike the NSPS, applies to an existing source. States are given a period of time to develop plans to implement a 111(d) Standard, and if a state does not develop such a plan, EPA will prescribe a plan for that state.

While the potential impact of a 111(d) standard on Big Stone is not yet known, standards of performance for GHGs, especially for existing sources, are anticipated to focus on efficiency improvements rather than add-on controls. The Co-Owners have in the past implemented efficiency measures at Big Stone through installation of a more efficient steam turbine at the Plant. The capital cost of efficiency improvements could be offset in whole or in part by reduced fuel costs.

To identify potentially viable alternatives for economic evaluation, OTP, on behalf of the Co-Owners first identified the needs currently served by the Big Stone Plant, as well as the basic operating characteristics of the Plant. The Big Stone Plant is a key baseload asset for its three utility Co-Owners, serving the existing load of customers in several states. The Plant is the largest baseload resource for each of the Co-Owners. Given the critical resource role played by the Big Stone Plant, OTP, on behalf of the Co-Owners developed alternatives that were capable of reliably: (1) producing approximately 3 million megawatt-hours of electricity per year; (2) serving as a baseload resource, with the ability to follow load and be a dispatchable resource with high availability; and (3) being in operation prior to expiration of the deadline for Big Stone to comply with the BART requirement. Analysis performed by the Midwest Independent Transmission System Operator ("MISO") has assumed the presence of a baseload generation source at the Big Stone site, and any change in location would require a reevaluation of the transmission system.

Given the significant customer load served by the Big Stone Plant, the Co-Owners identified coal, hydropower, nuclear and natural gas as practical potential replacement options that could

meet the above criteria.[50] Since the proposed AQCS Project includes continuation of coal generation at the Plant, another coal option was not considered as an alternative response scenario. Hydropower and new nuclear generation were rejected because expected permitting difficulties suggest that these resources could not be available in the timeframe required for compliance with the SD Haze SIP and its implementing rules and because the size of these alternatives to be economic, would exceed the needs of the Co-Owners. Based on these considerations, it was determined that natural gas was the only viable retirement/replacement or repowering option that could potentially replace the current functions of the Big Stone Plant in the required timeframe.

With respect to natural gas, three different scenarios were assessed:

1) Converting the existing Big Stone boiler to natural gas combustion;
2) Constructing a new gas-fired combined-cycle turbine at the Big Stone site, abandoning the existing equipment at the Plant; and
3) Combining a new gas combined-cycle turbine at the Big Stone site with wind generation.

Due to the timing of the compliance requirement for operation of the AQCS under the SD Haze SIP, it is unlikely that any of these three natural gas scenarios could be engineered, designed, permitted, procured, and constructed in the same timeframe as the Big Stone AQCS Project. Consequently, there would like be a minimum period of one to three additional years between the retirement of the current Big Stone Plant and the availability of these new resources, during which time OTP, NorthWestern Energy and Montana-Dakota would be dependent on the market or contracted purchases to meet the needs of their customers for the three million MWh per year currently provided by Big Stone. Assessment of the natural gas scenarios are provided below.

Other repowering scenarios were considered and ultimately rejected as infeasible, including one scenario involving repowering the existing generating unit with biomass. Biomass fuel may be capable of co-firing up to 10% of the heat input of the Plant, but this would not remove the AQCS Project requirement if coal still comprised 90% of the fuel mix. Achieving a 10% level of biomass as fuel would require drawing on most of the available biomass in a 30 to 50-mile radius, with an estimated delivered cost of $8 to $9 per million Btus. This is approximately four times higher than the cost of coal and approximately twice that of natural gas. The conversion to biomass fuel is not a viable response scenario because the AQCS Project would still be required, as well as the cost and logistical challenges involved in securing sufficient biomass fuel.[51]

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[50] Conservation and load management were not considered as a feasible alternative response scenario to replace this significant existing baseload facility, as conservation and load management are already assumed to be necessary to meet future resource needs.

[51] The most readily available source of biomass in the area is corn stover. This fuel would likely be delivered in large round bales with 20 to 25 bales per semi-load. At the current firing rate, the Big Stone Plant would need to consume close to ten of these large bales every minute due to the low Btu value, high moisture and low density of the fuel. Thus, biomass co-firing is not a viable regulatory response scenario.

The Co-Owners also rejected as infeasible a scenario involving the construction of a gas-fired combustion turbine and a heat-recovery boiler at the Big Stone site, and the use of that steam generation to power the existing Plant turbine. To implement this type of conversion, approximately two-thirds of the generation would come from the new gas-fired generation and one-third would come from the existing steam turbine. The existing steam turbine at Big Stone produces 475 megawatts. Using the 1/3 to 2/3 ratio, the generation from the Big Stone Plant would be required to increase from 475 megawatts to 1,425 megawatts. This additional generation would overload available transmission, since there are already over 2,000 megawatts in the queue at the Big Stone site for additional transmission, and thus could not be available before the AQCS Project's compliance deadline. In addition, this scenario would generate roughly 1,000 megawatts of additional intermediate load generation that is unlikely to fit the needs of the current Big Stone Co-Owners. Due to the time delay, the mismatch of resources and the high cost for such a sizeable gas plant, this response scenario was not further evaluated.

2. Comparative Analysis of the Financial Impacts of Proposed AQCS Project and Alternative Regulatory Response Scenarios

To assess financial impacts, the Co-Owners retained the engineering firm of Burns & McDonnell to perform a pro forma economic analysis to calculate the levelized costs of power for the AQCS Project and the alternative response scenarios.[52]

To simplify the analysis, Burns & McDonnell assumed that all response scenarios would be available by January 1, 2016. This assumption favors the alternative scenarios because the Burns & McDonnell analysis does not include any allowance to cover the need to purchase energy from the market during the period, very likely to run at least one to three years (2016 to 2018), between the retirement of Big Stone and the commercial operation of the natural gas scenarios.[53]

To perform its analysis, Burns & McDonnell, as much as possible, used the same modeling inputs as provided by OTP in its most recently filed Minnesota Integrated Resource Plan ("IRP") in Minnesota Docket No. E017/RP-10-623. Courtesy copies were filed with the North Dakota Public Service Commission in late June of 2010. When the necessary inputs for this ADP analysis were not available in the IRP filing, Burns & McDonnell's assumptions were based upon either the analyses prepared by Sargent & Lundy for OTP or the recent project experience of Burns & McDonnell, including its work on projects involving more than 25 gigawatts of gas-fired generation in the last ten years.[54] Montana-Dakota reviewed the assumptions provided by OTP and agrees that the Burns & McDonnell analyses reasonably represent alternatives available to Montana-Dakota.

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[52] The Burns & McDonnell analysis is provided in Attachment 9.

[53] OTP has estimated that the likely cost to enter into a Power Purchase Agreement ("PPA") to meet customer needs during the lag period would be between $87 million and $262 million. This estimate assumed the lowest cost option would be a coal PPA.

[54] The Sargent & Lundy analyses are provided in Attachments 5, 6, and 8.

Burns & McDonnell's analysis covers a 20-year period of operation (which provides a reasonable time period for cost recovery and is within the useful life of the equipment being added and the existing plant) and levelizes construction and operation (including fuel) costs into a levelized cost per Megawatt Hour (MWh). In addition to considering a Base Case analysis, Burns & McDonnell also calculated energy costs if stranded asset costs were included in the repowering and retirement/replacement scenarios and if additional costs for environmental controls for mercury and coal ash were included in the AQCS scenario.

a. Base Case Analysis

As provided in Joint Exhibit 2, Burns & McDonnell analysis found the AQCS Project the most economical scenario by a substantial margin.[55] Under the Base Case scenario, the AQCS Project is the lowest cost option by 41% over the next lowest cost option, the combined cycle plus wind. Adding the stranded asset cost to the combined cycle plus wind option increases this differential in the cost of energy between these two options to 47%, while adding the high environmental costs to the AQCS reduces the cost differential to 35%.[56]

Table 2 below (also presented in Joint Exhibit 2) provides the results of the Burns & McDonnell analysis. The estimated cost for each scenario in the Base Case analysis is provided in the horizontal row identified as "Combined Levelized Energy Cost." The estimated levelized energy costs if stranded asset costs are included for the repowering and retirement/replacement scenarios is provided in the horizontal row "Stranded Asset Cost Scenario." And, the estimated levelized energy costs if additional costs for environmental controls for mercury and coal ash disposal are included in the AQCS option is provided in the row marked as "High Environmental Cost Scenario."[57]

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[55] Attachment 9 at 6-12.

[56] Attachment 9 at 6-7.

[57] Under the High Environmental Cost Scenario, Burns & McDonnell assumed an additional $5 million in capital cost and $2 million in O & M cost for mercury emission control and an additional $6.66 million for handling coal ash if it is characterized as a special waste under the RCRA hazardous waste rules. Attachment 9 at 6.

Table 2 – Estimated Levelized Energy Cost (2016$/MWh)[58]

	Big Stone + AQCS	CCGT + Wind	CCGT	Big Stone with Natural Gas
Combined Levelized Energy Cost – (Base Case)	$70.89	$100.43	$103.38	$117.25
Total Energy Cost Including Stranded Asset Cost	$70.89	$104.24	$107.19	$117.25
Total Energy Cost Including High Environmental Costs	$74.56	$100.43	$103.38	$117.25

b. Sensitivity Analyses

In addition to the Base Case analysis, Burns & McDonnell prepared three sensitivity analyses to assess the effects of capital cost variations, fuel cost variations and operational cost variations.

(1) Capital Cost Sensitivity Analysis

In this analysis, Burns & McDonnell ran a sensitivity case to consider the effect of a range of capital costs (plus or minus 30%). In all cases, the AQCS Project was the low cost scenario and by a substantial margin. For the low end of the range for capital costs (minus 30%), levelized costs of energy for the AQCS Project were estimated to be $64.07 MWh compared to $93.74 MWh for the next least cost scenario (combined cycle and wind). For the high end of the range for capital costs (plus 30%), the levelized energy cost for the AQCS Project was $77.72 MWh compared to $107.12 MWh for the next lowest cost option (combined cycle wind).[59]

(2) Fuel Cost Sensitivity Analysis

In this analysis, Burns & McDonnell ran a sensitivity analysis to determine the impact of changes to the fuel costs for each option. The analysis considered the effect of a range of fuel costs (plus or minus 20%). Over the range of fuel costs evaluated, the AQCS Project was preferred in all instances. For the low end of the range of fuel costs (minus 20%), levelized costs of energy for the AQCS Project were estimated to be $63.45 MWh compared to $90.09 MWh for the next least cost scenario (combined cycle). For the high end of the range for capital costs (plus 20%), the levelized energy cost for the AQCS Project was $78.34 MWh compared to $106.63 MWh for the next lowest cost option (combined cycle wind).[60]

(3) O & M Sensitivity Analysis

A sensitivity analysis was performed to determine the impact of changes in O & M costs (plus or minus 20%). The AQCS Project was the preferred option over the range of costs evaluated. In

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[58] Attachment 9 at 6, Table 2.

[59] Attachment 9 at 8, Figure 1.

[60] Attachment 9 at 9, Figure 2.

all cases, the AQCS Project was the low cost scenario and by a substantial margin. For the low end of the range for O & M costs (minus 20%), levelized costs of energy for the AQCS Project were estimated to be $68.73 MWh compared to $99.47 MWh for the next least cost scenario (combined cycle and wind). For the high end of the range for capital costs (plus 20%), the levelized energy cost for the AQCS Project was $73.06 MWh compared to $101.38 MWh for the next lowest cost option (combined cycle wind).[61]

3. Comparative Analysis of the Operational Impacts of Proposed AQCS Project and Alternative Regulatory Response Scenarios

The financial analysis makes a comparison between the Big Stone AQCS Project and other regulatory response scenarios based on having response scenarios fully capable of replacing the capacity, energy output and dispatchable qualities provided by the Big Stone Plant. There are, however, additional operational differences that are likely to occur between the Big Stone AQCS and implementation of any of the natural gas-based regulatory response scenarios.

a. <u>Operational Issues for All Natural Gas Response Scenarios</u>

All three natural gas scenarios will impose significantly higher costs per MWh of electricity produced than would the AQCS Project. This in turn means that while the natural gas response scenarios are *capable* of replacing the Big Stone Plant's capacity and energy output, they are likely to be run at significantly lower capacity factors, requiring more frequent access to the market for energy purchases. As a result, significant amounts of power would be purchased at prices lower than the natural gas scenarios, but considerably higher than the energy cost of Big Stone after installation of the AQCS.

For example, an energy purchase of $95/MWh in the Base Case analysis would be economical compared to the natural gas scenarios, but would be $22/MWh more expensive than power that could be produced by Big Stone with the AQCS Project. To the extent that market price at any given time does not support the operation of natural gas plants, this power is likely to be produced through other means, including by coal-fired power plants.[62] And in situations where less power is available on the market, the natural gas scenarios would need to be employed, at substantial additional cost to the utilities' customers.

The market price/operating cost dynamics that will lower the capacity factors for the natural gas response scenarios also reduce their usefulness for load following wind resources. A high capacity factor baseload resource such as the current Big Stone Plant (and the Big Stone Plant with AQCS) is running many more hours of the year (for example, 85% of the time compared to

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[61] Attachment 9 at 10, Figure 3.

[62] The AQCS Project will significantly reduce SO_2 and NO_x emissions from the Plant, while maintaining current high control of particulate matter. In addition, mercury control is planned to target a 90% emission reduction, implemented at the same time as the AQCS. In general, the natural gas options are expected to require installation of NO_x control, but have little emissions of the other pollutants. The extent to which natural gas scenarios would result in less emissions of these pollutants would depend on what the source is for power purchased on the market to fill in for the expected lower capacity factor of the natural gas scenarios.

50% or less of the time), allowing its power output to be increased and decreased quickly in a load following function without the need for a full start up or shut down of the unit.

Deploying any of the natural gas scenarios thus includes dramatically increasing the exposure of the utilities' customers to the market price of power and to fluctuations in the price of natural gas, while reducing the load following capability of the Plant. The next sections assess operational impacts that are individual to each regulatory response scenario.

b. Repowering the Big Stone Plant with Natural Gas

Repowering the Big Stone Plant's boiler to burn natural gas is the highest cost option in the Base Case and among the various sensitivity analyses. Repowering would be less efficient than a new CCGT, which is illustrated by the substantially higher fuel cost in the Base Case ($99.70/MWh), compared with the other natural gas response scenarios ($66.44/MWh). The high operating cost of the repowered unit would likely result in limited use of the Plant.[63] As a result, the repowering scenario would expose customers to both additional market purchases and more expensive market purchases than the other natural gas scenarios.

A repowered unit would take approximately two days to start up and shut down, considerably longer than a new CCGT. High market prices would therefore need to be predicted for a long period of time to justify start up of a repowered unit. In addition, this start up time, combined with a limited use profile, would make a repowered unit unable to effectively load follow wind energy resources on the utilities' electric systems.

c. Retirement and Replacement with Natural Gas Combined Cycle Plant

Replacement of the Big Stone Plant with a new natural gas combined cycle unit at the Big Stone site was evaluated in two scenarios: CCGT and CCGT/Wind Power Purchases. Both scenarios are significantly higher cost in the Base Case, as well as in all sensitivity analyses.

Operationally, the CCGT scenario would allow a faster start up and shut down time than the repowering scenario. CCGTs would start up or shut down in 3-5 hours, substantially slower than a peaking unit such as a Simple Cycle Gas Turbine, which can start up in 10 minutes.[64] Due to its cost of power per MWh, however, a CCGT would likely have an intermediate, rather than a baseload, capacity factor of about 30 to 50%. This would make it less desirable for load following because it would have many more hours during the year when it is not operating at all. Load following would therefore require more start ups and shut downs than for a baseload plant, increasing the O & M costs for the unit. When a CCGT unit is running, however, it would be capable of increasing or decreasing its output to follow load.

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[63] The repowered unit would be expected to have the highest cost per MWh, despite its relatively lower capital cost ($267 million) than the other natural gas response scenarios ($621.29 million), because its lower efficiency increases its fuel cost per MWh of power produced. *See* Attachment 9 at 6, Table 2.

[64] A Simple Cycle Gas Turbine ("SCGT") is not a viable alternative response scenario, because it cannot replace the Big Stone Plant as a baseload resource.

The CCGT and CCGT/Wind Power Purchases scenarios have similar costs per MWh through the different sensitivity analyses, with the CCGT slightly more expensive except in the case of a drop in the price of natural gas of 10% or more. The capital cost of the CCGT scenarios, $621,289,115 (2016$), is about 27% higher than the capital cost of the Big Stone AQCS Project.

C. CONCLUSION

The financial analysis demonstrates that the Big Stone AQCS is the most economic scenario in the Base Case, and in the Base Case with an increase for Stranded Asset Costs and for anticipated environmental costs ("High Environmental Cost"). The Base Case analysis comparing installation of the AQCS with various options for repowering or retiring and replacing the Plant with natural gas shows that the AQCS is the most cost-effective option, with the cost of the other options 41% or more higher than the levelized MWh cost of the proposed AQCS. The AQCS remains the most cost-effective option under several sensitivity analyses concerning capital cost (+/-30%), fuel cost (+/-20%) and O & M cost (+/-20%).

Under multiple scenarios that consider potential changes in capital, O & M and fuel costs, the Big Stone AQCS remains the least cost option. This conclusion does not change when considering the potential for additional costs that may be imposed by anticipated environmental regulation. Repowering is the highest cost natural gas scenario, with the worst load following capability. Retirement of the Plant and replacement with a CCGT has a significantly higher capital cost than the Big Stone AQCS.

Implementation of any of the natural gas response scenarios instead of the Big Stone AQCS would unreasonably expose North Dakota customers to significantly higher costs under a wide range of potential future conditions. In addition, deploying any of the natural gas scenarios dramatically increases the exposure of North Dakota customers to the market price of power and to fluctuations in the price of natural gas, while reducing the load following capability of the Plant.

The assessment of the financial and operational inputs of the anticipated regulations to the Big Stone Plant demonstrates that the proposed AQCS Project is reasonable and prudent.

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October 3, 2011

Reply to Fergus Falls office
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Mr. Darrell Nitschke
Director of Administration/Executive Secretary
North Dakota Public Service Commission
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RE: Updated Information

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Application for Advance Determination of Prudence Big Stone Air Quality Control System Project
Case No. PU-11-163

Otter Tail Power Company Application for Advance Determination of Prudence Big Stone Air Quality Control System Project
Case No. PU-11-165

Dear Mr. Nitschke:

On August 18, 2011, the South Dakota Board of Minerals and Environment approved revisions to the Regional Haze Rules proposed by the South Dakota Department of Environment and Natural Resources. The revisions were suggested by the U.S. Environmental Protection Agency.

The Regional Haze Rules were approved by the South Dakota Interim Rules Review Committee on August 30, 2011, and became effective on September 19, 2011. The South Dakota Regional Haze State Implementation Plan (SIP) was also revised to address EPA's suggestions.

Because the South Dakota Regional Haze SIP and Regional Haze Rules were originally filed with the Applicants' Applications for Advance Determination of Prudence as Attachments 1 and 3, respectively, for informational purposes we are filing one original and seven copies of the revised versions of each. I have been authorized by Montana-Dakota Utilities Co. to request that these documents be filed in Case No. PU-11-163, as well.

The revisions do not affect South Dakota’s best available retrofit technology determination or the Big Stone AQCS project cost projections.

Sincerely,

/s/ MARK B. BRING
Mark B. Bring
Associate General Counsel

wao
By electronic filing
Enclosures

STATE OF MINNESOTA)
) SS.
COUNTY OF OTTER TAIL)

AFFIDAVIT OF SERVICE

RE: Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Application for Advance Determination of Prudence Big Stone Air Quality Control System Project
Case No. PU-11-163

Otter Tail Power Company Application for Advance Determination of Prudence
Big Stone Air Quality Control System Project
Case No. PU-11-165

I, Wendi A. Olson, being first duly sworn on oath, deposes and says: that on the 3rd day of October, 2011, I served the attached updated information filing, of Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., and Otter Tail Power Company, on Mr. Darrell Nitschke and the North Dakota Public Service Commission by e-mail and over-night mail and to all other persons list below by email.

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/s/ WENDI A. OLSON

Subscribed and sworn to before me this
3rd day of October, 2011.

/s/ DIANE LUANN MERZ

Diane LuAnn Merz
Notary Public, My Commission Expires on January 31, 2015.

SOUTH DAKOTA'S

REGIONAL HAZE

STATE IMPLEMENTATION PLAN

South Dakota Department of Environment and Natural Resources

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Executive Summary

The Department of Environment and Natural Resources (DENR) worked with the Western Regional Air Partnership (WRAP), states not members of WRAP, federal land managers, the Environmental Protection Agency (EPA), the regulated community, and others to develop this document as part of South Dakota's Regional Haze State Implementation Plan (SIP). This document along with the applicable Administrative Rules of South Dakota (ARSD) and the addition of ARSD, Chapter 74:36:21 will be South Dakota's Regional Haze State Implementation Plan and implemented by DENR to ensure South Dakota's Regional Haze Program meets the goal of achieving natural conditions in the Badlands and Wind Cave National Parks by 2064 as specified in Title 40 of the Code of Federal Regulations (CFR) §51.308.

Chapter 1 provides background information on the initial federal visibility protection program, describes the causes of visibility impairment, and describes the new federal regional haze program regulations. Chapter 2 provides information on South Dakota's two Class I areas. The two Class I areas are the Badlands National Park and Wind Cave National Park and both are located in the western third of South Dakota.

Chapter 3 describes the process DENR followed to determine natural conditions, baseline conditions, and the uniform rate of improvement for both Class I areas. Chapter 4 discusses the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring data for both Class I areas. This chapter looked at the aerosols impacting both Class I areas, what time of year they occur, and if they are increasing or decreasing over time.

Chapter 5 describes South Dakota's emission inventory for past, present, and future air emission inventories in South Dakota, what type of activities are emitting the air emissions, and if the air emissions are generated within South Dakota or from neighboring states and countries. Chapter 6 describes the BART review DENR conducted and establishes the BART requirements for the BART-eligible sources in South Dakota. The BART review covers an analysis to determine BART-eligible sources, a modeling analysis to determine if the BART-eligible source contributes to visibility impairment in a Class I area, and the establishment of BART for those BART-eligible sources that reasonably contribute to visibility impairment in any Class I area.

The BART review identified one electrical generating unit subject to the BART requirements. Otter Tail Power Company's Big Stone I facility determined that it reasonably contributes to visibility impairment in Class I areas. DENR determined the control equipment considered BART for Big Stone I is the existing baghouse, a semi-dry flue gas desulfurization system, and selective catalytic reduction. The installation of the new control equipment and establishment of BART emission limits, compliance demonstration, recordkeeping, and reporting requirements will be established in an air quality construction permit and eventually in Otter Tail Power Company's Title V air quality operating permit. The installation of the new control equipment and other requirements will be completed within five years of EPA's approval of South Dakota's Regional Haze State Implementation Plan.

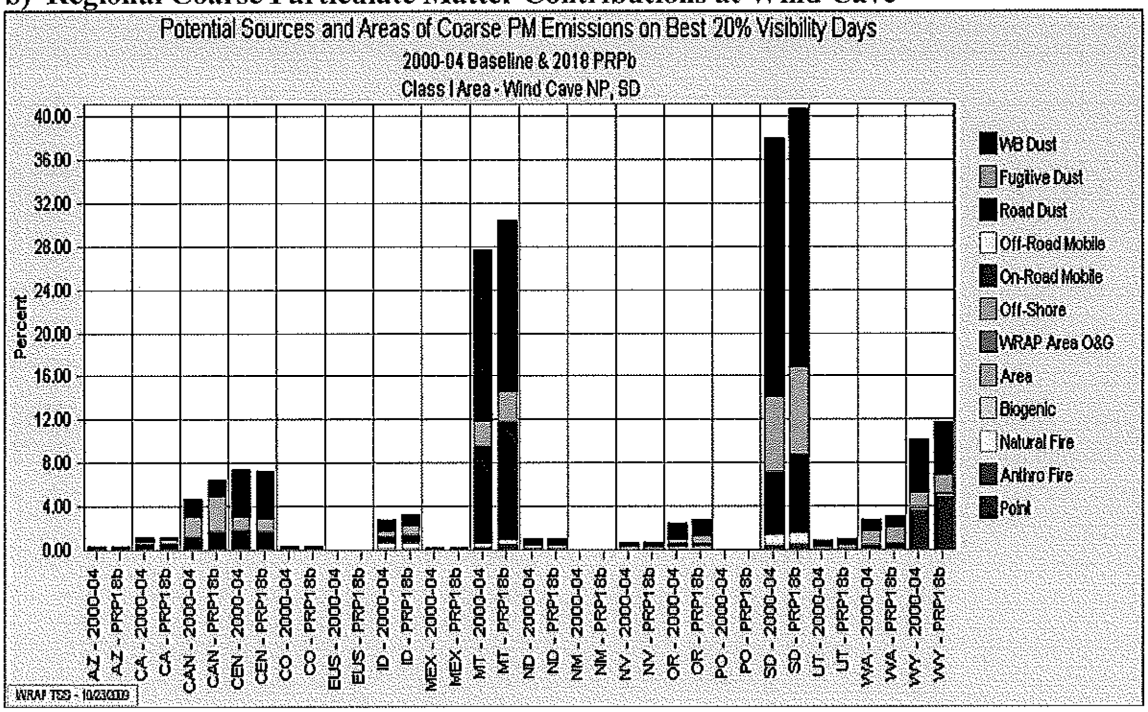
Chapter 7 discusses South Dakota's goals for demonstrating reasonable progress such as outlining existing rules that already help minimize air emissions that cause visibility impairment and the modeling WRAP conducted of the western United States to determine if states are meeting the reasonable progress goals in 2018. Sulfur dioxide emissions in South Dakota from 2002 through 2018 are expected to decline by 36%, nitrogen oxides emissions are expected to decline by 18%, organic carbon mass emissions are expected to decline by 6%, and elemental carbon emissions are expected to decline by 49%. Other states will also experience a reduction in air emissions that reasonably contribute to visibility impairment in Class I areas. Overall, sulfur dioxide emissions during the same time period are expected to decline by 26%, nitrogen oxide emissions are expected to decline by 29%, organic carbon mass are expected to decline by 6%, and elemental carbon emissions are expected to decline by 31%. These reductions are expected to demonstrate reasonable progress is being made to improve visibility at all Class I areas.

Chapter 8 describes South Dakota's long-term goals in achieving natural conditions by 2064. It also outlines DENR's proposed rules (ARSD, Chapter 74:36:21) to ensure new sources and modifications to existing sources will not reasonably contribute to visibility impairment at any Class I area. In addition, DENR will review, develop, and implement a Smoke Management Plan to address wildfires and prescribed fires.

Chapter 9 discusses DENR's monitoring plan for tracking our progress in achieving natural conditions by 2064. Chapter 10 describes the consultation DENR went through with federal land managers, states, and the public, how DENR responded to each comment, and their future involvement.

Chapter 11 describes the reviews and reporting DENR will perform to track South Dakota's progress in attaining natural conditions by 2064.

b) Regional Coarse Particulate Matter Contributions at Wind Cave



(WRAP TSS – http://vista.cira.colostate.edu/tss/)

6.0 Best Available Retrofit Technology (BART)

6.1 Bart-Eligible Sources

In accordance with 40 CFR § 51.308(e), South Dakota's State Implementation Plan is required to contain emission limitations representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I area. A BART-eligible source is an existing stationary facility that is any of the following stationary sources of air pollutant that was not in operation prior to August 7, 1962, was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any air pollutant. Fugitive emissions must be included in the potential to emit, to the extent quantifiable.

1. Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input,
2. Coal cleaning plants (thermal dryers),
3. Kraft pulp mills,
4. Portland cement plants,
5. Primary zinc smelters,
6. Iron and steel mill plants,
7. Primary aluminum ore reduction plants,
8. Primary copper smelters,
9. Municipal incinerators capable of charging more than 250 tons of refuse per day,

10. Hydrofluoric, sulfuric, and nitric acid plants,
11. Petroleum refineries,
12. Lime plants,
13. Phosphate rock processing plants,
14. Coke oven batteries,
15. Sulfur recovery plants,
16. Carbon black plants (furnace process),
17. Primary lead smelters,
18. Fuel conversion plants,
19. Sintering plants,
20. Secondary metal production facilities,
21. Chemical process plants,
22. Fossil-fuel boilers of more than 250 million British thermal units per hour heat input,
23. Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,
24. Taconite ore processing facilities,
25. Glass fiber processing plants, and
26. Charcoal production facilities.

In February 2004, DENR followed the procedures in 40 CFR Part 51, Appendix Y in identifying emission units at stationary facilities in South Dakota meeting the above categories, identifying the startup date of the emission units, comparing the potential emissions to the 250 tons per year cutoff, and identifying the emissions units and pollutants that constitute the BART-eligible sources. The following terms are defined below:

1. "In Operation" means engaged in activity related to the primary design function of the source. The date the unit is permitted is not important to meet this test because the focus is on actual operation of the unit;
2. "In Existence" means that the owner or operator has obtained all necessary preconstruction approvals or permits required by federal, state, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time;
3. "Date of Reconstruction" must occur during the August 7, 1962 to August 7, 1977 time period; and
4. "Potential to Emit" means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source. However, fugitive emissions, to the extent quantifiable, must be counted for the 26 categories.

In accordance with 40 CFR § 51.308(e)(1)(i), Table 6-1 provides a list of existing stationary facilities from the February 2004 analysis that may be considered a BART-eligible source and need further investigation to determine if they are subject to BART.

Table 6-1– List of BART-Eligible Sources [1]

Unit	Date	Maximum Capacity	Potential to Emit				BART Eligible
			TSP	SO_2	NOx	VOC	
Northern States Power Company – Sioux Falls							
#1 – Babcock boiler	1969	330 MMBtus/hr	7	1	795	2	Yes
#2 – Babcock boiler	1969	330 MMBtus/hr	7	1	795	2	Yes
#3 – Babcock boiler	1969	330 MMBtus/hr	7	1	795	2	Yes
Total =		**990 MMBtus/hr**	**21**	**3**	**2,385**	**6**	**Yes**
Pete Lien and Sons, Inc. – Rapid City							
#6 – Vertical kiln	1966	-	561	0	13	1	Yes
#7 – Pebble lime crusher	1970	-	1	0	0	0	Yes
#8 – Large hydrator	1965	-	97	0	0	0	Yes
#12 – Lime bagging	1963	-	48	0	0	0	Yes
Total =			707	0	13	1	**Yes**
Otter Tail Power Company – Big Stone I Power Plant							
#1 – Babcock boiler	1975	5,609 MMBtus/hr	300	19,863	17,179	125	**Yes**

[1] – "TSP" means total suspended particulate, "SO_2" means sulfur dioxide, "NOx" means nitrogen oxide, and "VOCs" means volatile organic compounds.

In accordance with 40 CFR Part 51, Appendix Y, the next step is to identify those BART-eligible sources that may "*emit any pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility.*" For each source subject to BART, DENR is required to identify the best system of continuous emission control technology for each source after considering the following as specified in section 169A(g)(2) of the federal CAA:

1. Cost of compliance;
2. The energy and non-air quality environmental impacts of compliance;
3. Any existing pollution control technology in use at the source;
4. The remaining useful life of the source; and
5. The degree of visibility improvement which may reasonably be anticipated from the use of BART.

The results of the BART review are required to be submitted in the Regional Haze State Implementation Plan identifying the BART emission limitations and timeline for demonstrating compliance. The timeline for demonstrating compliance shall not exceed five years after EPA approves the Regional Haze State Implementation Plan. DENR may establish design, equipment, work practice or other operational standards when limitations on measurement technologies make emission standards infeasible.

6.1.1 Northern States Power Company – Sioux Falls

The three units at Northern States Power Company in Sioux Falls, South Dakota is considered fossil-fuel fired steam electric plant. The units were built in 1969 and have a maximum capacity greater than 250 million Btus per hour per unit. However, Northern States Power Company decommissioned these three units and they are no longer permitted to operate in Northern States Power Company's Title V air quality permit. Therefore, these three units at Northern States Power Company's Sioux Falls site are not subject to BART.

6.1.2 Pete Lien and Sons, Inc. – Rapid City

Pete Lien and Sons operates a limestone quarry operation and lime plant in northwest Rapid City. There are four operations that were identified in the February 2004 analysis, not in operation prior to August 7, 1962, and in existence on August 7, 1977. The four operations are a 1966 vertical kiln, 1970 pebble lime crusher, 1965 large hydrator, and 1963 lime bagging operation. Only the 1966 vertical kiln has the potential to emit over the 250 tons per year threshold.

As identified in Pete Lien and Sons' existing Title V air quality permit issued November 12, 2008, the 1970 pebble lime crusher was replaced with a 1982 pebble lime crusher and the 1963 bagging operation was replaced with a 2004 lime bagging operation. Therefore, these two units will not be evaluated further.

Pete Lien and Sons falls under the "lime plant" category listed above. DENR researched the definition of "lime plant" to determine if the large hydrator is included in the definition of a lime plant. DENR determined that typically the definition for the 26 categories coincides with the definitions under the New Source Performance Standards. Under 40 CFR Part 60, Subpart HH, a lime manufacturing plant means, "*... any plant which used a rotary lime kiln to produce lime product from limestone by calcinations.*" Based on this definition of a lime plant, Pete Lien and Sons would not be considered a lime plant because the kiln in question is a vertical kiln and not a rotary kiln. In addition, only the kiln would be considered a "lime plant".

DENR assumed the vertical kiln was considered a lime plant and on April 21, 2006, DENR requested that WRAP model Pete Lien and Sons emissions to determine if they would cause or contribute to any impairment of visibility in a Class I area. WRAP initiated this process by running CALMET/CALPUFF modeling using WRAP's "*CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States,*" August 15, 2006. The basic assumptions in the protocol are:

1. Use of three years of modeling consisting of calendar year 2001, 2002 and 2003;
2. Visibility impacts due to emissions of sulfur dioxide, nitrogen oxide and primary particulate matter emissions were calculated. Unless a state provided speciated particulate matter emissions, all PM emissions were modeled as $PM_{2.5}$. In this case all PM emissions were modeled as $PM_{2.5}$;
3. Visibility was calculated using the original IMPROVE equation and annual average natural conditions; and
4. CALPUFF version 6.112 was used in the analysis.

The CALPUFF modeling procedures are outlined in WRAP's BART Modeling Protocol, which can be reviewed at the following website:

http://pah.cert.ucr.edu/aqm/308/bart/WRAP_RMC_BART_Protocol_Aug15_2006.pdf.

Table 6-2 provides a summary of the modeling outputs based on annual sulfur dioxide and nitrogen oxide emissions of 0.4 and 277 tons per year, respectively.

Table 6-2– WRAP's Modeling Results for Pete Lien and Sons [1]

Class I Area	State	Minimum Distance	Max Delta (dv)	99th (dv)	Days >0.5	Annual 98th percentile		
						2001	2002	2003
Badlands	SD	73 km	0.267	0.140	0	0.120	0.160	0.105
Boundary Waters	MN	946 km	0.014	0.007	0	0.005	0.003	0.003
Bridger	WY	489 km	0.021	0.003	0	0.001	0.002	0.001
Fitzpatrick	WY	501 km	0.018	0.002	0	0.001	0.001	0.001
Grand Teton	WY	570 km	0.005	0.001	0	0.000	0.000	0.000
Lostwood	ND	509 km	0.040	0.009	0	0.006	0.005	0.007
Medicine Lake	MT	488 km	0.030	0.011	0	0.006	0.005	0.010
North Absaroka	WY	487 km	0.008	0.002	0	0.001	0.001	0.001
Teton	WY	513 km	0.009	0.001	0	0.001	0.001	0.000
Theodore Roosevelt	ND	311 km	0.049	0.023	0	0.014	0.016	0.015
Ul Bend	MT	516 km	0.024	0.006	0	0.005	0.003	0.005
Voyageurs	MN	921 km	0.012	0.006	0	0.004	0.002	0.003
Washakie	WY	461 km	0.019	0.003	0	0.001	0.002	0.001
Wind Cave	SD	52 km	0.366	0.203	0	0.128	0.137	0.139
Yellowstone	WY	524 km	0.008	0.002	0	0.001	0.001	0.001

[1] - "dv" means deciview and "km" means kilometers.

The modeling conducted by WRAP demonstrated that Pete Lien and Sons did not cause or contribute to visibility impairment at a Class I area. After reviewing the modeling inputs, DENR determined the vertical kiln should be modeled again because of errors in the UTM coordinates and emission rates. However, before the modeling could be re-run, the vertical kiln was shutdown and dismantled in 2009.

Although Pete Lien and Sons' existing Title V air quality permit still identifies the vertical kiln as a unit, permit condition 1.1 specifies in the footnote of Table 1-1 that Pete Lien and Sons is required to shutdown and dismantle the vertical kiln before the initial startup of Unit #45. Pete Lien and Sons fulfilled this commitment by notifying DENR on March 13, 2009, that the vertical kiln was shutdown and dismantled. Therefore, Pete Lien and Sons' shutdown and dismantled the unit subject to BART and DENR did not re-model the vertical kiln.

6.1.3 Otter Tail Power Company – Big Stone I

Unit #1 at the Big Stone I Power Plant was built in 1975, has a maximum capacity greater than 250 million Btus per hour, and has the potential to emit greater than 250 tons per year of any air pollutant. The next step in this analysis is to determine if Unit #1's emissions may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area. On April 21, 2006, DENR requested that WRAP model Unit #1's emissions from Otter Tail Power Company's Big Stone I Power Plant.

WRAP initiated this process by running CALMET/CALPUFF modeling using WRAP's "CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States," August 15, 2006. The basic assumptions in the protocol are:

1. Use of three years of modeling of 2001, 2002 and 2003;
2. The sulfur dioxide, nitrogen oxide and particulate emission rates represent the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled, not including periods of startup, shutdown, or malfunctions;
3. Visibility impacts due to emissions of sulfur dioxide, nitrogen oxide and primary particulate matter emissions were calculated. Unless a state provided speciated particulate matter emissions, all PM emissions were modeled as $PM_{2.5}$;
4. Visibility was calculated using the original IMPROVE equation and annual average natural conditions; and
5. CALPUFF version 6.112 was used in the analysis.

The CALPUFF modeling procedures are outlined in WRAP's BART Modeling Protocol and can be reviewed at the following website:

http://pah.cert.ucr.edu/aqm/308/bart/WRAP_RMC_BART_Protocol_Aug15_2006.pdf.

Table 6-3 provides a summary of the modeling outputs based on annual sulfur dioxide and nitrogen oxide emissions of 12,409 and 15,580 tons per year, respectively. The annual sulfur dioxide and nitrogen oxide emissions were derived from WRAP's BART protocol identified above.

Table 6-3– WRAP's Modeling Results for Otter Tail Power Company Big Stone I [1]

Class I Area	State	Min Distance	Max Delta (dv)	99th (dv)	Days >0.5	Annual 98th percentile 2001	2002	2003
Badlands	SD	470 km	3.047	1.076	21	0.364	0.417	**0.683**
Boundary Waters	MN	431 km	1.653	1.133	63	**0.951**	**0.659**	**1.034**
Bridger	WY	1,041 km	0.147	0.003	0	0.001	0.001	0.000
Fitzpatrick	WY	1,050 km	0.079	0.005	0	0.001	0.001	0.000
Grand Teton	WY	1,112 km	0.029	0.003	0	0.001	0.001	0.000
Lostwood	ND	585 km	0.779	0.370	7	0.263	0.175	0.204
Medicine Lake	MT	690 km	0.678	0.345	7	0.256	0.211	0.218
North Absaroka	WY	1,013 km	0.121	0.026	0	0.011	0.008	0.001
Teton	WY	1,052 km	0.049	0.008	0	0.004	0.002	0.001
Theodore Roosevelt	ND	555 km	2.061	0.840	27	**0.581**	0.443	**0.687**

Class I Area	State	Min Distance	Max Delta (dv)	99th (dv)	Days >0.5	Annual 98th percentile 2001	2002	2003
Ul Bend	MT	902 km	0.840	0.196	3	0.089	0.065	0.043
Voyageurs	MN	438 km	1.658	0.915	52	**0.666**	**0.703**	**0.729**
Washakie	WY	1,006 km	0.090	0.018	0	0.007	0.005	0.001
Wind Cave	SD	572 km	1.545	0.631	13	0.224	0.263	0.261
Yellowstone	WY	1,049 km	0.068	0.018	0	0.009	0.004	0.001

[1] - "dv" means deciview and "km" means kilometers.

WRAP had determined that Big Stone I would be reasonably anticipated to contribute to an impairment of visibility at the Badlands National Park in South Dakota, Theodore Roosevelt National Park in North Dakota, and Boundary Waters Wilderness and Voyageurs National Park in Minnesota.

6.2 Otter Tail Power Company's Modeling Results

Otter Tail Power Company was notified of the results and requested an opportunity to verify the results after identifying several errors in actual emission rates and stack parameters. The department allowed Otter Tail Power Company to re-run the models using the correct emission rates and stack parameters. On March 19, 2008, Otter Tail Power Company submitted an individual source analysis using CALMET/CALPUFF; but after review by the state, EPA, and federal land managers (U.S. Fish and Wildlife Service, U.S. Forest Service and National Park Service) it was determined that a BART modeling protocol should be submitted and approved by all parties, Otter Tail Power Company would run the model using the approved protocol, and submit before Otter Tail Power Company's results could be approved.

Otter Tail Power Company submitted the BART modeling protocol on January 16, 2009. After several conference calls and discussions, a revised protocol identified as June 2009, was submitted July 1, 2009. After several submittals and conference calls, Otter Tail Power Company committed to make the following changes to the protocol in an email dated August 31, 2009:

1. Although Otter Tail Power Company attached the CALMET switches it would use, it committed to using the CALMET switches recommended and approved by EPA and Federal Land Managers (FLMs) dated August 20, 2009. However, to ensure the most up-to-date CALMET switches are used, DENR is requiring Otter Tail Power Company to use the CALMET switches identified in EPA's memorandum dated August 31, 2009, from Tyler J Fox, Group Leader, Air Quality Modeling Group, to EPA Regional Modeling Contacts. The date on the listing of CALMET switches is August 28, 2009. The memorandum may be viewed in Attachment C.
2. Otter Tail Power Company committed to use the CALPUFF switches that Penny Shamblin, with Hunton and Williams, submitted to DENR by email on August 19, 2009. Although the document contains CALMET switches, only the CALPUFF switches (see Attachment D) in this email will be used by Otter Tail Power Company in the BART analysis. The CALMET switches mentioned above will be the ones used in the analysis.

3. Otter Tail Power Company proposes to revise the June 2009 modeling protocol by using a 12 kilometer MM5 grid and a 4 kilometer CALMET grid rather than the 4 kilometer MM5 grid and 4 kilometer CALMET grid identified in the June 2009 modeling protocol. DENR reviewed other acceptable modeling protocols and is acceptable to this change.
4. Although Otter Tail Power Company may run POSTUTIL option MNITRATE=2 for its own purposes, the modeling results DENR will accept for the BART analysis will be MNITRATE=1.

The CALPUFF switches Otter Tail Power Company is recommending contains five switches that are different than those recommended by EPA as defaults. The following identifies the variable, EPA's default, recommended default by Otter Tail Power Company, and DENR's response:

1. "NSPEC" – Identifies the number of species modeled. The EPA default is 5 and Otter Tail Power Company is proposing 11, which follows the FLM guidance on particle speciation and size. DENR is agreeable to this change.
2. "NSE" – Number of species emitted. The EPA default is 3 and Otter Tail Power Company is proposing 9.
3. "MSPLIT" – Allows puffing. The EPA default is 0 (No) and Otter Tail Power Company is proposing 1 (Yes). Puff splitting in necessary due to the distance from Big Stone I to a federal Class I area. DENR is agreeable to this change.
4. "MESHDN" – Grid receptor spacing. The EPA default is 1; however, Otter Tail Power Company is stating this is "Not Applicable". DENR is agreeable to this change.
5. "BCKNH3" – Ammonia background. The EPA default is 10 parts per billion and Otter Tail Power Company is recommending 1 part per billion. During the June 3, 2009, conference call, EPA stated it was okay with this change. DENR is agreeable to this change.

On September 18, 2009, the department determined that Otter Tail Power Company's BART modeling protocol as identified above. See Appendix A for the approval letter and the BART modeling protocol dated June 2009.

The modeling results identified that Otter Tail Power Company's Big Stone I Power Plant would be reasonably anticipated to contribute to an impairment of visibility at the Boundary Waters and Voyageurs federal Class I areas in northern Minnesota and the Isle Royale federal Class I area in Michigan. The reasonably anticipated to contribute to an impairment is based on visibility impacts greater than 0.5 deciview based on the 98th percentile at the three federal Class I areas. See Appendix B for the modeling report dated October 2009, and Table 6-4 for a summary of the modeling results.

Table 6-4– Otter Tail Power Company's Modeling Results for Big Stone I[1]

Class I Area	State	Min Distance	Max Delta (dv)	99th (dv)	98th (dv)
Badlands	SD	470 km	2.202	0.698	**0.481 (0.5)**
Boundary Waters	MN	431 km	3.574	1.351	**1.079 (1.1)**
Lostwood	ND	585 km	1.110	0.722	0.409 (0.4)
Theodore Roosevelt	ND	555 km	2.232	0.772	**0.459 (0.5)**
Voyageurs	MN	438 km	2.162	1.376	**0.724 (0.7)**
Wind Cave	SD	572 km	1.671	0.591	0.325 (0.3)
Isle Royale	MI	1,049 km	1.806	0.789	**0.665 (0.7)**

1 - "dv" means deciview and "km" means kilometers.

Otter Tail Power Company results did not match up entirely with the modeling conducted by WRAP. In particular, Otter Tail Power Company's modeling also showed that Big Stone I would reasonably contribute to impairment at the Isle Royale National Park in Michigan. DENR believes Otter Tail Power Company's modeling best represent the visibility impacts from Big Stone I since the original modeling did not have the correct emission rates and stack parameters and the CALPUFF modeling conducted by Otter Tail Power Company included puff splitting, which helps improve the accuracy of the model when used for great distances.

In accordance with the 40 CFR Part 51, Appendix Y, DENR used a contribution threshold of 0.5 deciviews for determining if Otter Tail Power Company's Big Stone I facility is subject to BART. The guideline provides the state the discretion to set a threshold below 0.5 deciviews if "the location of a large number of BART-eligible sources within the state and proximately to a Class I area justifies this approach. The discretion was based on the following factors:

1. It equates to the 5 percent extinction threshold for new sources under the PSD New Source Review rules;
2. It is consistent with the threshold selected by other states in the west, which all selected 0.5 deciviews; and
3. It represents the limit of perceptible change.

DENR chose the 0.5 deciview threshold because there is only one source that is BART-eligible and it is greater than 300 kilometers from any Class I area. Therefore, DENR will establish this threshold in its proposed ARSD Chapter 74:36:21 – Regional Haze Program. Otter Tail Power Company's Big Stone I power plant exceeded this threshold and is subject to BART. In accordance with 40 CFR § 51.308(e)(1)(i), the only source subject to BART in South Dakota is Otter Tail Power Company's Big Stone I facility.

In accordance with 40 CFR § 51.308(e)(1)(ii), DENR requested that Otter Tail Power Company complete a Case-by-Case BART analysis, which includes determining the visibility improvements expected at each of these Class I areas (see Appendix C).

6.3 Otter Tail Power Company's Case-by-Case BART Analysis

In accordance with 40 CFR 51.301, Best Available Retrofit Technology (BART) is defined as *"an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."*

In accordance with 40 CFR § 51.308(e)(1)(ii)(B), the determination of BART for fossil fuel fired power plants having a total generating capacity greater than 750 megawatts must be made pursuant to the guidelines in Appendix Y of this part (Guidelines for BART Determinations under the Regional Haze Rule). Appendix Y identifies a five step process in determining BART. The five steps are as follows:

1. STEP 1—Identify All Available Retrofit Control Technologies: In identifying ''all'' options, one should identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology. The list is complete if it includes the maximum level of control each technology is capable of achieving. Where a New Source Performance Standard (NSPS), under 40 CFR Part 60, exists for a source category, one should include a level of control equivalent to the NSPS as one of the control options;
2. STEP 2—Eliminate Technically Infeasible Options: One evaluates the technical feasibility of the control options identified in Step 1. One should document a demonstration of technical infeasibility and should explain, based on physical, chemical, or engineering principles, why technical difficulties would preclude the successful use of the control option on the emissions unit under review. One may then eliminate such technically infeasible control options from further consideration in the BART analysis;
3. STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies: One evaluates the control effectiveness of all the technically feasible control alternatives identified in Step 2 for the pollutant and emissions unit under review. Two key issues in this process include: (1) Make sure that you express the degree of control using a metric that ensures an ''apples to apples'' comparison of emissions performance levels among options; and (2) Give appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels;
4. STEP 4—Evaluate Impacts and Document the Results: Once the available and technically feasible control technology options are identified, one should conduct the following analyses when you make a BART determination: (1) Impact analysis part 1 – costs of compliance; (2) Impact analysis part 2 – energy impacts, (3) Impact analysis part 3 – non-air quality environmental impacts; and (4) Impact analysis part 4 – remaining useful life; and
5. STEP 5—Evaluate Visibility Impacts: One should evaluate the net visibility improvement form the available and technically feasible control technology options.

This is accomplished by modeling the pre-control and post-control emission rates according to an accepted methodology.

In determining what is considered BART, Appendix Y identifies that the state should develop a chart (or charts) displaying each of the alternatives and include: (1) Expected emission rate (e.g., tons per year, pounds per hour); (2) Emissions performance level (e.g., percent pollutant removed, emissions per unit product, pounds per million Btus, parts per million); (3) Expected emissions reductions (e.g., tons per year); (4) Costs of compliance (e.g., total annualized costs in dollars, cost effectiveness (dollar per ton), incremental cost effectiveness (dollar per ton), any other cost-effectiveness measures (dollar per deciview)); (5) Energy impacts; (6) Non-air quality environmental impacts; and (7) Modeled visibility impacts.

Otter Tail Power Company's Big Stone I facility does not have a total generating capacity greater than 750 megawatts. Therefore, DENR is not required to follow these guidelines. As such, DENR will follow the steps identified in Appendix Y with some slight differences. For example, in identifying the available control technologies, DENR is not listing any of the permutations of the control levels for each identified control technology as suggested by EPA's guidance. DENR will use the initial step to identify control technologies without including the control levels. Step 3 is used to evaluate the control effectiveness or permutations of the control levels for those control technologies that are considered feasible to install or maintain as identified in Step 2.

6.3.1 Particulate BART Review

6.3.1.1 Particulate Control Technologies

Step 1 requires the identification of all available retrofit control technologies. The particulate matter emissions from fossil-fuel fired units can be categorized as either filterable or condensable particulate. The filterable particulate matter exists as a solid or liquid particle in the exhaust of a boiler as it leaves the stack. As such, the filterable particulate may be collected by placing a control device in the flue gas stream prior to the stack. Condensable particulates are emitted out the stack in a gaseous state but rapidly condense into particles when released into the atmosphere and cooled. Therefore, condensable particulates may not be readily collected by placing a control device in the stack.

Those control technologies being reviewed under Step 1 are those that would control the filterable particulate matter. Otter Tail Power Company identified the following control options for particulate matter.

1. Existing fabric filter (baghouse);
2. New fabric filter (baghouse);
3. Compact hybrid particulate collector; and
4. Electrostatic precipitator.

DENR also identified two more control technologies that may be used to control particulate emissions and are listed below:

1. Wet scrubber; and
2. Cyclone(s)/Multicyclone(s).

6.3.1.2 Technically Feasible Particulate Control Technologies

Step 2 requires the elimination of any control technologies identified in Step 1 that are technically infeasible. A compact hybrid particulate collector is a combination of an electrostatic precipitator and a baghouse in series. The compact hybrid particulate collector is generally operated with a higher air-to-cloth ratio than a typical baghouse. Since Otter Tail Power Company already has a baghouse installed at Big Stone I, Otter Tail did not further consider the compact hybrid particulate collector.

Even though Otter Tail Power Company identified a reason for not selecting the compact hybrid particulate collector, the reasoning does not identify that the technology is infeasible to install. Since both an electrostatic precipitator and a baghouse are both technically feasible options and without further evidence, DENR considers the compact hybrid particulate collector as a feasible control technology.

DENR determined that the following particulate control technologies were feasible for Otter Tail Power Company:

1. Existing fabric filter (baghouse);
2. New fabric filter (baghouse);
3. Compact hybrid particulate collector;
4. Electrostatic precipitator;
5. Wet scrubber; and
6. Cyclone(s)/Multicyclone(s).

6.3.1.3 Particulate Control Effectiveness

Step 3 requires the evaluation of control effectiveness for each control technology. DENR evaluated the control effectiveness by comparing the effectiveness in Table 6.5.

Table 6-5 – Comparison of Control Effectiveness for Particulate Controls

		Emission Rate		Control Efficiency	
		Otter Tail [1]	RBLC [3]	PFDR [4]	IEA [5]
Rank	**Control**	**(lbs/MMBtus) [2]**	**(lbs/MMBtus) [2]**	**(%)**	**(%)**
#1	**Baghouse**	0.015	0.010 to 0.03	95 to 99.9	>99 to >99.9999
#2	**Electrostatic Precipitator**	0.015	0.015 to 0.03	80 to 99.5	>99 to >99.99
#3	**COHPAC [6]**	Not Provided	0.015	Not Identified	Not Identified
#4	**Wet Scrubber(s)**	Not Provided	Not Identified	75 to 99	90 to 99.9
#5	**Cyclone(s)/ Multicyclone(s)**	Not Provided	Not Identified	50 to 95	75 – 99

[1] – The identified emission rates were identified in Otter Tail Power Company's BART analysis;
[2] – "lbs/MMBtus" means pounds per million British thermal units;
[3] – The identified emission rates were obtained from EPA's Reasonable Achievable Control Technology, Best Available Control Technology, and Lowest Achievable Emission Rate Clearinghouse (RBLC) considering data for permits issued after calendar year 2000;
[4] – The control efficiencies, in percent removal, are derived from page 473 of "Particulates and Fine Dust Removal Process and Equipment by Marshal Sittig";
[5] – The control efficiencies, in percent removal, are derived from the IEA Clean Coal Centre's Webpage at http://www.iea-coal.org.uk/site/ieacoal/home; and
[6] – "COHPAC" means Compact Hybrid Particulate Collector.

6.3.1.4 Particulate Control Technology Impacts

In Step 4, DENR looked at impacts associated with the control alternatives such as cost of compliance, energy impacts, non-air quality environmental impacts, and the remaining useful life of the project. These impacts are intended to provide rational in choosing between the alternative control options when determining what is considered BART. Otter Tail Power Company already has installed and is operating a baghouse, which is the top particulate control technology. Therefore, there is no additional compliance cost, energy impacts, etc. that Otter Tail Power Company would have to endure. As such, no additional impacts analysis will be conducted to determine the appropriate controls for particulate matter.

6.3.2 Sulfur Dioxide BART Review

6.3.2.1 Sulfur Dioxide Control Technologies

Step 1 requires the identification of all available retrofit control technologies. Otter Tail Power Company identified the following control options for sulfur dioxide:

1. Fuel switching;
2. Semi-dry flue gas desulfurization; and
3. Wet flue gas desulfurization.

DENR also identified the following control technologies that may be used to control sulfur dioxide emissions:

1. Coal cleaning;
2. Coal upgrading;
3. Hydrated lime injection; and
4. Emerging control technologies such as Enviroscrub, Electro catalytic oxidation, and Airborne process.

6.3.2.2 Technically Feasible Sulfur Dioxide Control Technologies

Fuel switching is a viable method to reduce sulfur dioxide emissions by switching to a fuel with lower sulfur content. Otter Tail Power Company's Big Stone facility's primary fuel source is subbituminous coal obtained from the Powder River Basin in Wyoming. Powder River Basin subbituminous coal has one of the lowest sulfur contents available in the United States. As such, Otter Tail Power Company has already implemented fuel switching.

Coal cleaning is typically performed by physical gravimetric separation which is capable of reducing sulfur, ash and impurities from the coal. The effectiveness of gravimetric separation is dependent on the ash content and the distribution of fuel bound sulfur between organic and inorganic. If the sulfur compounds are predominantly inorganic materials, then coal cleaning is fairly effective, but if the sulfur compounds are predominantly organic materials, then coal cleaning is not effective. Physical cleaning or gravimetric separation may be effective with bituminous coals that contain high levels of inorganic sulfur and ash. However, gravimetric coal cleaning is not technically feasible for low sulfur, low ash, and low inorganic-sulfur content coal such as the coal from the Powder River Basin in Wyoming. Otter Tail Power Company's Big Stone facility's primary fuel source is subbituminous coal obtained from the Powder River Basin in Wyoming. As such, coal cleaning is not a technical feasible option for Otter Tail Power Company.

Coal upgrading such as a process developed by Evergreen Energy (formerly KFx) called the K-Fuel process enriches the coal by utilizing high pressure and temperature conditions to reduce moisture and inorganic materials. Typically, the K-Fuel process is utilized to reduce the moisture content and increase the coal heating value, however, the process may remove some sulfur compounds. Evergreen Energy constructed a K-Fuel production facility in Gillette, Wyoming which may produce approximately 750,000 tons per year of K-Fuel. Otter Tail Power Company burned approximately 2,268,000 tons of coal in 2008. As such, coal upgrading is not a technically feasible option for Otter Tail Power Company because there is not enough being produced to supply Otter Tail Power Company's needs. In addition, based on Evergreen Energy's webpage, this facility has been idle since calendar year 2008.

Hydrated lime injection is a system that injects hydrated lime prior to the particulate collection system. The hydrated lime absorbs the sulfur dioxide and is collected in the particulate control device. Hydrated lime is also referred to as calcium hydroxide. The sulfur dioxide reacts with the calcium hydroxide to form calcium sulfate or calcium sulfite. Fly ash from the Powder River Basin has a calcium content of up to 30 percent. Since the Powder River Basin coal is already providing additional calcium to adsorb sulfur dioxide, the hydrated lime will not likely provide additional sulfur dioxide removal. Otter Tail Power Company's primary fuel source is subbituminous coal obtained from the Powder River Basin in Wyoming. As such, hydrated lime injection is not considered a technically feasible option for Otter Tail Power Company since the concept is already taking place by using Power River Basin coal.

Emerging control technologies such as Enviroscrub, Electro catalytic oxidation, and the Airborne process have not been commercially available and have not been demonstrated for long-term levels of performance. As noted in 40 CFR Part 51, Appendix Y, a control technology needs to be commercially available to be considered technically feasible. As such these emerging technologies are not considered technically feasible options for Otter Tail Power Company.

DENR determined that the following sulfur dioxide control technologies were feasible for Otter Tail Power Company:

1. Semi-dry flue gas desulfurization; and
2. Wet flue gas desulfurization.

6.3.2.3 Sulfur Dioxide Control Effectiveness

Step 3 requires the evaluation of control effectiveness for each control technology. DENR evaluated the control effectiveness by comparing the effectiveness in Table 6.6.

Table 6-6 – Comparison of Control Effectiveness for Sulfur Dioxide Controls

		Emission Rate			Control Efficiency
		Otter Tail [1]	RBLC [3]	Basin [4]	EPA [5]
Rank	**Control**	**(lbs/MMBtus) [2]**	**(lbs/MMBtus) [2]**	**(lbs/MMBtus) [2]**	**(%)**
#1	**Wet Flue Gas Desulfurization**	0.043 to 0.15	0.1 to 0.167	0.05	90 to 98
#2	**Semi-Dry Flue Gas Desulfurization**	0.09 to 0.15	0.038 to 0.16	0.07	80 to 90

[1] – The identified emission rates were identified in Otter Tail Power Company's BART analysis;
[2] – "lbs/MMBtus" means pounds per million British thermal units;
[3] – The identified emission rates were obtained from EPA's Reasonable Achievable Control Technology, Best Available Control Technology, and Lowest Achievable Emission Rate Clearinghouse (RBLC) considering data for permits issued after calendar year 2000;
[4] – The emission rates are based on the BACT analysis provided by Basin Electric Power Cooperative's proposed NextGen project in South Dakota; and
[5] – The control efficiencies, in percent removal, are from EPA's "Air Pollution Control Technology Fact Sheet on Flue Gas Desulfurization Systems".

6.3.2.4 Sulfur Dioxide Control Technology Impacts

Step 4 requires DENR to look at impacts associated with the control alternatives such as cost of compliance, energy impacts, non-air quality environmental impacts, and the remaining useful life of the project. These impacts are intended to provide rational in choosing between the alternative control options when determining what is considered BART.

Otter Tail Power Company identified cost estimates for each of the control options. In addition, Otter Tail Power Company identified cost estimated for two different operating scenarios for each of the two control alternatives. Table 6-7 summarizes Otter Tail Power Company's estimated costs.

In 40 CFR Part 51, Appendix Y – Guidelines for BART Determination Under the Regional Haze Rule, in the section titled "How should I determine visibility impacts in the BART determination" it notes that the model should use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). The 18,000 tons per year of sulfur dioxide is based on the highest average 24-hour average emission rate (4,832 pounds per hour) for calendar years 2001 through 2003 and operating 85% of the time or 7,746 hours per year. Based on the BART guidelines, the baseline emissions are 18,000 tons per year.

Table 6-7 – Comparison of Control Effectiveness for Sulfur Dioxide Controls

Control Option	Capital Cost	O&M [1]	Annual Cost [2]	Reduction [3]	Cost Effectiveness [4]
WFGD #1 [5]	$171,800,000	$9,600,000	$29,050,000	17,100	$1,699
WFGD #2 [6]	$171,800,000	$9,490,000	$28,900,000	14,870	$1,944
SDFGD #1 [7]	$141,300,000	$7,660,000	$23,570,000	16,120	$1,462
SDFGD #2 [8]	$141,300,000	$7,480,000	$23,330,000	14,870	$1,569

[1] – O&M represents the operational and maintenance cost estimate for the control alternative;
[2] – Annual cost is the annualized cost for each control alternative taking into account both the capital and operational and maintenance costs;
[3] – Reduction represents the amount of sulfur dioxide reduced in tons per year annual from the baseline level of 18,000 tons of sulfur dioxide per year;
[4] – Cost Effectiveness represents the annualized cost divided by the identified emission reductions (dollar per ton);
[5] – WFGD #1 represents a wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[6] – WFGD #2 represents a wet flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[7] – SDFGD #1 represents a semi-dry flue gas desulfurization system meeting an emission rate of 0.9 pounds per million British thermal units; and
[8] – SDFGD #2 represents a semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units.

Otter Tail Power Company did not identify the cost effectiveness on a dollar per visibility reduction. DENR considered this cost effectiveness in Step 5 of the analysis.

Otter Tail Power Company identified the energy impacts cost associated for each of the control options. Table 6-8 summarizes Otter Tail Power Company's estimated energy impacts.

Table 6-8 – Estimated Energy Impacts for Sulfur Dioxide Controls

Control	Energy Demand	Percent of Generation
Wet Flue Gas Desulfurization	9,500 kilowatts	2.0 percent
Semi-Dry Flue Gas Desulfurization	3,325 kilowatts	0.7 percent

The non-air quality environmental impacts of the two control alternatives include the solid and aqueous waste streams. The semi-dry flue gas desulfurization system would be installed upstream of the existing baghouse. The baghouse would be used to collect the injected lime and reacted sulfur dioxide emissions along with other existing particulate matter emissions. Otter Tail Power Company did not identify how much additional particulate matter would be collected by the baghouse due to the use of the semi-dry flue gas desulfurization system. At this time, it is assume the additional material collected in the baghouse is negligible compared to the existing collection. Otter Tail Power Company estimates that the wet flue gas desulfurization system would generate an additional 44,700 tons of gypsum solids which would need to be properly disposed.

In conducting its cost analysis, Otter Tail Power Company used 30 years as the life expectancy averaging period for the control alternatives. Since the useful life of Otter Tail Power Company's Big Stone I facility is expected to be longer than 30 years, there is no difference between the control options based on useful life.

6.3.3 Nitrogen Oxide BART Review

6.3.3.1 Nitrogen Oxide Control Technologies

Step 1 requires the identification of all available retrofit control technologies. Otter Tail Power Company identified the following control options for nitrogen oxide:

1. Low-nitrogen oxide burners (LNBs);
2. Over-fire air (OFA);
3. Separated over-fire air (SOFA);
4. Selective non-catalytic reduction (SNCR);
5. Rich reagent injection (RRI); and
6. Selective catalytic reduction (SCR).

DENR also identifies the following control technologies that may be used to control nitrogen oxide emissions:

1. Flue-gas recirculation;
2. Oxygen enhanced combustion;
3. Catalytic absorption/oxidation;
4. Gas reburn; and
5. Emerging control technologies such as Enviroscrub, Electro-catalytic oxidation, NOxStar, and Cascade processes.

6.3.3.2 Technically Feasible Nitrogen Oxide Control Technologies

Low-nitrogen oxide burners limit nitrogen oxide formation by controlling the stoichiometric and temperature profiles of the combustion process. Low-nitrogen oxide burners attempt to delay the complete mixing of fuel and air as long as possible within the constraints of the furnace design. This is the reason flames from low-nitrogen oxide burners are longer than conventional burners. Cyclone furnace's length and diameter are not designed with sufficient size to allow for low-nitrogen oxide burners to be installed allowing stable combustion. As such, low-nitrogen oxide burners are not considered a technically feasible option for Otter Tail Power Company.

Flue-gas recirculation reduces the formation of thermal nitrogen oxide emissions in a boiler by limiting the amount of oxygen available for oxidation in the fuel rich zone of the boiler. Flue-gas recirculation is not known to reduce nitrogen oxide emissions any further when added with an over-fire air system. Therefore, Otter Tail Power Company did not conduct any further review of flue-gas recirculation. However, this reasoning does not justify that flue-gas recirculation is not a feasible technology to consider. Therefore, DENR will consider the flue-gas recirculation as a feasible control technology.

Catalytic absorption/oxidation such as SCONOx or EMx systems is a nitrogen oxide control technology that utilizes a proprietary catalytic oxidation and absorption technology which oxidizes nitrogen oxide (NO) and carbon monoxide (CO) to nitrogen dioxide (NO2) and carbon dioxide (CO2), respectively. The nitrogen dioxide is then absorbed onto an absorption media while carbon dioxide is released to the atmosphere. Once the absorption media becomes saturated, the nitrogen dioxide is desorbed and treated by a proprietary catalyst. The SCONOx system is being considered as a cross over technology to coal-fired boilers, but to date has only been applied to "clean flue gas" systems such as natural-gas fired combustions turbines. The catalytic absorption/oxidation system requires a high operating temperature and low particulate loading. Therefore, the system would have to be installed after the particulate control device and require a flue gas reheater. DENR was unable to find a coal-fired system that was using a catalytic absorption/oxidation system or find that this system was being marketed commercially for coal fired boilers. As noted in 40 CFR Part 51, Appendix Y, a control technology needs to be commercially available to be considered technically feasible. As such the catalytic absorption/oxidation system is not considered a technically feasible option for Otter Tail Power Company.

Gas reburning is a nitrogen oxide control technology that uses a second combustion zone following the primary combustion zone in the boiler. In a cyclone boiler, such as the one being operated at Otter Tail Power Company's Big Stone I facility, burning the coal produces molten slag along the cyclone barrels. The molten slag catches subsequent coal until the combustion is complete. Generally, cyclone burners operate near the slag-tapping limits. Therefore, using natural gas or another fuel source as the reburn fuel may inhibit the molten slag formation. In addition, by trying to lower the air to fuel ratio more than achieved by the existing over-fire air systems may cause slag "freezing" at low load levels. As such gas reburn is not considered a technically feasible option for Otter Tail Power Company.

Oxygen enhanced combustion is a nitrogen oxide combustion control technology that reduces the formation of thermal nitrogen oxides in the boiler. Developed by Praxair Technology Inc., this method uses oxygen in the burner instead of air to achieve additional nitrogen oxide reductions. To date, the largest demonstration of this technology is a 30 megawatt pilot demonstration at Babcock and Wilcock's Clean Environmental Development facility in Alliance, Ohio. As noted on Babcock and Wilcock's website - http://www.babcock.com/, the project was a pilot test of the technology and the next step is to demonstrate the technology at a commercial scale. As noted in 40 CFR Part 51, Appendix Y, a control technology needs to be commercially available to be considered technically feasible. As such the oxygen enhanced combustion is not considered a technically feasible option for Otter Tail Power Company.

Emerging control technologies such as Enviroscrub, Electro catalytic oxidation, and the Airborne process have not been commercially available and have not been demonstrated for long-term levels of performance. As noted in 40 CFR Part 51, Appendix Y, a control technology needs to be commercially available to be considered technically feasible. As such these emerging technologies are not considered technically feasible options for Otter Tail Power Company.

DENR determined that the following nitrogen oxide control technologies were feasible for Otter Tail Power Company:

1. Over-fire air (OFA);
2. Separated over-fire air (SOFA);
3. Selective non-catalytic reduction (SNCR);
4. Rich reagent injection (RRI);
5. Selective catalytic reduction (SCR) ; and
6. Flue-gas recirculation.

6.3.3.3 Nitrogen Oxide Control Effectiveness

Step 3 requires the evaluation of control effectiveness for each control technology. DENR evaluated the control effectiveness by comparing the effectiveness in Table 6.9.

Table 6-9 – Comparison of Control Effectiveness for Nitrogen Oxide Controls

		Emission Rate			Control Efficiency	
		Otter Tail [1]	RBLC [3]	Basin [4]	EPA [5]	IEA [6]
Rank	**Control**	**(lbs/MMBtus) [2]**	**(lbs/MMBtus) [2]**	**(lbs/MMBtus) [2]**	**(%)**	**(%)**
#1	**SCR and SOFA [7]**	0.10	0.05 to 0.1	0.05	35 to 90	80 to 90
#2	**RRI, SNCR and SOFA [8]**	0.20	0.07 to 0.15	0.10	35 to 90	30 to 50
#3	**SNCR and SOFA [9]**	0.35	0.07 to 0.15	0.10	35 to 90	30 to 50
#4	**Separated over-fire air**	0.50	Not Identified	Not Identified	30 to 70	Not Identified
#5	**Over-fire air**	0.65	Not Identified	Not Identified	30 to 70	Not Identified
#6	**Flue Gas Recirculation**	Not Identified	Not Identified	Not Identified	30 to 70	Not Identified

[1] – The identified emission rates were identified in Otter Tail Power Company's BART analysis;
[2] – "lbs/MMBtus" means pounds per million British thermal units;
[3] – The identified emission rates were obtained from EPA's Reasonable Achievable Control Technology, Best Available Control Technology, and Lowest Achievable Emission Rate Clearinghouse (RBLC) considering data for permits issued after calendar year 2000;
[4] – The emission rates are based on the BACT analysis provided by Basin Electric Power Cooperative's proposed NextGen project in South Dakota which is for a new pulverized-fired boiler equipped with a low-NOx burner combustion technology. The emission rates were primarily based on if the system used selective catalytic reduction or selective non-catalytic reduction;
[5] – The emission rates are from page 27 of the EPA's Technical Bulletin – *"Nitrogen Oxides; Why and How they are Controlled"*.
[6] – The emission rates were obtained from the IEA Clean Coal Centre's Webpage - http://www.iea-coal.org.uk/site/ieacoal/home. The emission rates were primarily based on if the system used selective catalytic reduction or selective non-catalytic reduction.

[7] – SCR and SOFA refers to selective catalytic reduction and separated over-fire air;
[8] – RRI, SNCR, and SOFA refers to rich reagent injection, selective non-catalytic reduction and separated over-fire air, respectively; and
[9] – SNCR and SOFA refers to selective non-catalytic reduction and separated over-fire air.

6.3.3.4 Nitrogen Oxide Control Technology Impacts

Step 4 requires DENR to look at impacts associated with the control alternatives such as cost of compliance, energy impacts, non-air quality environmental impacts, and the remaining useful life of the project. These impacts are intended to provide rational in choosing between the alternative control options when determining what is considered BART.

Otter Tail Power Company identified cost estimates for five control options. Table 6-10 summarizes Otter Tail Power Company's estimated costs.

In 40 CFR Part 51, Appendix Y – Guidelines for BART Determination Under the Regional Haze Rule, in the section titled "How should I determine visibility impacts in the BART determination" it notes that the model should use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). The 18,000 tons per year of nitrogen oxide is based on the highest average 24-hour average emission rate (4,855 pounds per hour) for calendar years 2001 through 2003 and operating 85% of the time or 7,746 hours per year. Based on the BART guidelines, the baseline emissions are 18,000 tons per year.

Table 6-10 – Comparison of Control Effectiveness for Nitrogen Oxide Controls

Control Option	Capital Cost	O&M [1]	Annual Cost [2]	Reduction [3]	Cost Effectiveness [4]
SCR and SOFA [5]	$81,800,000	$4,110,000	$13,210,000	16,000	$825
RRI, SNCR and SOFA [6]	$16,200,000	$7,260,000	$11,390,000	13,910	$818
SNCR and SOFA [7]	$11,900,000	$2,120,000	$3,990,000	10,780	$197
SOFA [8]	$4,800,000	$152,000	$650,000	7,640	$85
Over-fired air	$0	$106,000	$140,000	4,510	$31

[1] – O&M represents the operational and maintenance cost estimate for the control alternative;
[2] – Annual cost is the annualized costs for each control alternative taking into account both the capital and operational and maintenance costs;
[3] – Reduction represents the amount of nitrogen oxide reduced in tons per year annual from the baseline level of 18,000 tons of nitrogen oxide per year;
[4] – Cost Effectiveness represents the annualized cost divided by the identified emission reductions (dollar per ton);
[5] – SCR and SOFA refers to selective catalytic reduction and separated over-fire air;
[6] – RRI, SNCR, and SOFA refer to rich reagent injection, selective non-catalytic reduction and separated over-fire air;
[7] – SNCR and SOFA refers to selective non-catalytic reduction and separated over-fire air; and
[8] – SOFA refers to separated over-fire air.

Otter Tail Power Company did not identify a cost effectiveness on a dollar per visibility reduction. DENR considered this cost effectiveness in Step 5 of the analysis.

Otter Tail Power Company identified the energy impacts cost associated for each of the control options. Table 6-11 summarizes Otter Tail Power Company's estimated energy impacts.

Table 6-11 – Estimated Energy Impacts for Nitrogen Oxide Controls

Control	Energy Demand	Percent of Generation
Selective catalytic reduction and Separated over-fire air	400 to 1,000 kilowatts	Less than 0.2 percent
Rich reagent injection, Selective non-catalytic reduction and Separated over-fire air	150 to 400 kilowatts	Less than 0.1 percent
Selective non-catalytic reduction and Separated over-fire air	150 to 400 kilowatts	Less than 0.1 percent
Separated over-fire air	1 kilowatt	Negligible
Over-fire air	1 kilowatt	Negligible

The over-fire air and the separated over-fire air will increase the amount of unburned carbon in the flyash, which will increase the amount of flyash that needs to be properly disposed. Otter Tail Power Company considers this increase negligible compared to the existing amount flyash being properly disposed.

The selective non-catalytic reduction and the selective catalytic reduction will generate a small amount of unreacted ammonia or urea to be emitted. Even though ammonia and urea are not considered regulated air pollutants, these emissions are involved in the formation of ammonium sulfates and ammonium nitrates, which contribute to the amount of visibility impairment.

In conducting its cost analysis, Otter Tail Power Company used 30 years as the life expectancy averaging period for the control alternatives. Since the useful life of Otter Tail Power Company's Big Stone I facility is expected to be longer than 30 years, there is no difference between the control options based on useful life.

6.3.4 Visibility Impact Evaluations

In accordance with 40 CFR Part 51, Appendix Y, a source that has an impact equal to or greater than 1.0 deciviews is considered to "cause" a visibility impairment and that establishing a threshold for what is considered to "contribute" to a visibility impairment should not be any higher than 0.5 deciviews. DENR is proposing to define "contribute" to visibility impairment as a change in visibility impairment in a mandatory Class I federal area of 0.5 deciviews or more, based on a 24-hour average, above the average natural visibility baseline. A source exceeds the threshold when the 98^{th} percentile (eighth highest value) of the modeling results, based on one year of the three years of meteorological data modeled, exceeds the 0.5 deciviews.

Otter Tail Power Company modeled its existing operations impact on seven Class I areas that are located in Michigan, Minnesota, North Dakota, and South Dakota. Table 6-12 identifies the potential impact based on the 98^{th} percentile for the existing Big Stone I facility has while emitting approximately 18,000 tons of sulfur dioxide, 18,000 tons of nitrogen oxides, and 300 tons of particulate matter per year.

Table 6-12 – Potential Impact of Existing Big Stone I (98^{th} Percentile)

Class I Area	2002 [1,2]	2006 [1,2]	2007 [1,2]
Boundary Waters	0.574 (0.6)	0.790 (0.8)	1.079 (1.1)
Voyageurs	0.623 (0.6)	0.574 (0.6)	0.724 (0.7)
Wind Cave	0.305 (0.3)	0.120 (0.1)	0.325 (0.3)
Theodore Roosevelt	0.215 (0.2)	0.459 (0.5)	0.322 (0.3)
Lostwood	0.232 (0.2)	0.385 (0.4)	0.409 (0.4)
Badlands	0.452 (0.5)	0.481 (0.5)	0.471 (0.5)
Isle Royale	0.629 (0.6)	0.506 (0.5)	0.665 (0.7)

[1] – The modeling was conducted using the meteorological data for calendar years 2002, 2006, and 2007; and

[2] – The results are represented in deciviews. Otter Tail Power Company identified the deciview valued identified in the model to three decimal places which is consistent with how WRAP reported the visibility impacts in Table 6-3. The value in parentheses represents the value that is used to compare to the proposed contribution threshold of 0.5.

Based on the modeling results, Otter Tail Power Company's Big Stone I facility contributes to visibility impairment at Boundary Waters, Voyageurs, Theodore Roosevelt, Badlands, and Isle Royale because they have a deciview impact of 0.5 or greater.

Otter Tail Power Company conducted visibility modeling for 10 different control option scenarios and each scenario for three calendar years worth of meteorological data. The 10 different control option scenarios simultaneously considered the emissions of nitrogen oxide, sulfur dioxide, and particulate matter. Table 6-13 identifies the emission rates used in the modeling for each different control option.

Table 6-13 – Emission Rates for Each Control Option

Option	Control Equipment	SO2 [11]	NOx [12]	PM10 [13]
#1	OFA and Dry FGD #1 [1]	841.4	3645.9	84.1
#2	OFA and Wet FGD #1 [2]	841.4	3645.9	84.1
#3	OFA and Dry FGD #2 [3]	504.8	3645.9	84.1
#4	OFA and Wet FGD #2 [4]	241.2	3645.9	84.1
#5	SOFA and Dry FGD #1 [5]	841.4	2804.5	84.1
#5a	SOFA and Dry FGD #2 [6]	504.8	2804.5	84.1
#5b	SOFA and Wet FGD #2 [7]	241.2	2804.5	84.1
#6	SNCR, SOFA, and Dry FGD #1 [8]	841.4	1963.2	84.1
#7	RRI, SNCR, SOFA, and Dry FGD #1 [9]	841.4	1121.8	84.1
#8	SCR, SOFA, and Dry FGD #1 [10]	841.4	560.9	84.1

[1] – OFA and Dry FGD #1 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[2] – OFA and Wet FGD #1 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[3] – OFA and Dry FGD #2 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[4] – OFA and Wet FGD #2 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[5] – SOFA and Dry FGD #1 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[6] – SOFA and Dry FGD #2 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[7] – SOFA and Wet FGD #2 refers to separated over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[8] – SNCR, SOFA, and Dry FGD #1 refers to selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[9] – RRI, SNCR, SOFA, and Dry FGD #1 refers to rich reagent injection, selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[10] – SCR, SOFA, and Dry FGD #1 refers to selective catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[11] – SO2 represents the sulfur dioxide emission rate in pounds per hour;
[12] – NOx represents the nitrogen oxide emission rate in pounds per hour; and
[13] – PM10 represents the particulate matter less than 10 microns emission rate in pounds per hour.

Table 6-14 provides the results of the modeling (98th percentile) using the different control options and emissions rates in Table 6-13. Again, Otter Tail Power Company identified the deciview valued identified in the model to three decimal places which is consistent with how WRAP reported the visibility impacts in Table 6-3. The value in parentheses represents the value that DENR used to compare to the proposed contribution threshold of 0.5.

Table 6-14 – Modeling Results for Each Control Option (98th Percentile – Deciviews)

Option	Control Equipment	Class I Area	2002	2006	2007
#1	OFA and Dry FGD #1 [1]	Boundary Waters	0.330 (0.3)	0.548 (0.5)	**0.657 (0.7)**
		Voyageurs	0.329 (0.3)	0.399 (0.4)	0.460 (0.5)
		Isle Royale	0.377 (0.4)	0.296 (0.3)	0.339 (0.3)
		Badlands	0.223 (0.2)	0.176 (0.2)	0.241 (0.2)
		Theodore Roosevelt	0.092 (0.1)	0.247 (0.2)	0.190 (0.2)
#2	OFA and Wet FGD #1 [2]	Boundary Waters	0.360 (0.4)	0.546 (0.5)	**0.667 (0.7)**
		Voyageurs	0.349 (0.3)	0.494 (0.5)	0.521 (0.5)
		Isle Royale	0.367 (0.4)	0.273 (0.3)	0.323 (0.3)
		Badlands	0.234 (0.2)	0.199 (0.2)	0.254 (0.3)
		Theodore Roosevelt	0.099 (0.1)	0.244 (0.2)	0.161 (0.2)
#3	OFA and Dry FGD #2 [3]	Boundary Waters	0.319 (0.3)	0.534 (0.5)	**0.620 (0.6)**
		Voyageurs	0.307 (0.3)	0.391 (0.4)	0.450 (0.5)
		Isle Royale	0.363 (0.4)	0.287 (0.3)	0.323 (0.3)
		Badlands	0.219 (0.2)	0.172 (0.2)	0.230 (0.2)
		Theodore Roosevelt	0.087 (0.1)	0.234 (0.2)	0.173 (0.2)
#4	OFA and Wet FGD #2 [4]	Boundary Waters	0.350 (0.4)	0.521 (0.5)	**0.611 (0.6)**
		Voyageurs	0.312 (0.3)	0.464 (0.5)	0.502 (0.5)
		Isle Royale	0.351 (0.4)	0.250 (0.3)	0.290 (0.3)
		Badlands	0.225 (0.2)	0.191 (0.2)	0.234 (0.2)
		Theodore Roosevelt	0.084 (0.1)	0.230 (0.2)	0.138 (0.1)
#5	SOFA and Dry FGD #1 [5]	Boundary Waters	0.264 (0.3)	0.433 (0.4)	0.524 (0.5)
		Voyageurs	0.263 (0.3)	0.314 (0.3)	0.364 (0.4)
		Isle Royale	0.298 (0.3)	0.235 (0.2)	0.272 (0.3)
		Badlands	0.169 (0.2)	0.137 (0.1)	0.191 (0.2)
		Theodore Roosevelt	0.076 (0.1)	0.199 (0.2)	0.156 (0.2)
#5a	SOFA and Dry FGD #2 [6]	Boundary Waters	0.250 (0.3)	0.419 (0.4)	0.493 (0.5)
		Voyageurs	0.249 (0.2)	0.306 (0.3)	0.354 (0.4)
		Isle Royale	0.285 (0.3)	0.226 (0.2)	0.256 (0.3)
		Badlands	0.165 (0.2)	0.133 (0.1)	0.180 (0.2)
		Theodore Roosevelt	0.069 (0.1)	0.186 (0.2)	0.141 (0.1)
#5b	SOFA and Wet FGD #2 [7]	Boundary Waters	0.274 (0.3	0.407 (0.4)	0.478 (0.5)
		Voyageurs	0.244 (0.2)	0.365 (0.4)	0.393 (0.4)
		Isle Royale	0.274 (0.3)	0.195 (0.2)	0.227 (0.2)
		Badlands	0.174 (0.2)	0.147 (0.1)	0.182 (0.2)
		Theodore Roosevelt	0.066 (0.1)	0.180 (0.2)	0.108 (0.1)
#6	**SNCR, SOFA, and Dry FGD #1** [8]	**Boundary Waters**	**0.200 (0.2)**	**0.318 (0.3)**	**0.388 (0.4)**
		Voyageurs	**0.196 (0.2)**	**0.228 (0.2)**	**0.267 (0.3)**
		Isle Royale	**0.221 (0.2)**	**0.174 (0.2)**	**0.199 (0.2)**
		Badlands	**0.120 (0.1)**	**0.098 (0.1)**	**0.143 (0.1)**

Option	Control Equipment	Class I Area	2002	2006	2007
		Theodore Roosevelt	0.063 (0.1)	0.150 (0.2)	0.121 (0.1)
#7	RRI, SNCR, SOFA, and Dry FGD #1 [9]	Boundary Waters	0.137 (0.1)	0.202 (0.2)	0.256 (0.3)
		Voyageurs	0.130 (0.1)	0.157 (0.2)	0.176 (0.2)
		Isle Royale	0.142 (0.1)	0.115 (0.1)	0.134 (0.1)
		Badlands	0.090 (0.1)	0.066 (0.1)	0.099 (0.1)
		Theodore Roosevelt	0.050 (0.1)	0.101 (0.1)	0.080 (0.1)
#8	SCR, SOFA, and Dry FGD #1 [10]	Boundary Waters	0.097 (0.1)	0.136 (0.1)	0.170 (0.2)
		Voyageurs	0.086 (0.1)	0.107 (0.1)	0.123 (0.1)
		Isle Royale	0.092 (0.1)	0.077 (0.1)	0.098 (0.1)
		Badlands	0.079 (0.1)	0.060 (0.1)	0.070 (0.1)
		Theodore Roosevelt	0.036 (0.0)	0.070 (0.1)	0.064 (0.1)

[1] – OFA and Dry FGD #1 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[2]- OFA and Wet FGD #1 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[3] - OFA and Dry FGD #2 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[4] - OFA and Wet FGD #2 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[5] – SOFA and Dry FGD #1 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[6] – SOFA and Dry FGD #2 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[7] – SOFA and Wet FGD #2 refers to separated over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[8] – SNCR, SOFA, and Dry FGD #1 refers to selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[9] - RRI, SNCR, SOFA, and Dry FGD #1 refers to rich reagent injection, selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units; and
[10] - SCR, SOFA, and Dry FGD #1 refers to selective catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units.

Based on the modeling results in Table 6-14, Otter Tail Power Company would have to use Option #6, #7, or #8 to not reasonably contribute to visibility impairment in the Boundary Waters, Voyageurs, Isle Royale, Badlands, and Theodore Roosevelt National Parks.

Otter Tail Power Company did not provide a cost per deciview reduction for each of the proposed control options. DENR calculated a cost per deciview reduction by summing the annualized cost of each of the control alternatives associated with the control options and dividing by the visibility reduction identified by the modeling from the baseline condition. Table 6-15 provides a cost per deciview comparison.

Table 6-15 – Cost per Deciview Comparison ($/deciview)

Option	Control Equipment	Class I Area	2002	2006	2007
#1	OFA and Dry FGD #1 [1]	Boundary Waters	$ 96,188,525	$ 96,983,471	$ 55,616,114
		Voyageurs	$ 79,829,932	$ 134,114,286	$ 88,901,515
		Isle Royale	$ 93,134,921	$ 111,761,905	$ 71,993,865
		Badlands	$ 102,489,083	$ 79,950,820	$ 102,043,478
		Theodore Roosevelt	$ 190,813,008	$ 110,707,547	$ 177,803,030
		Cumulative	**$ 15,998,637**	**$ 16,108,442**	**$ 13,542,989**
#2	OFA and Wet FGD #1 [2]	Boundary Waters	$ 135,700,935	$ 119,016,393	$ 70,485,437
		Voyageurs	$ 105,985,401	$ 363,000,000	$ 143,054,187
		Isle Royale	$ 110,839,695	$ 124,635,193	$ 84,912,281
		Badlands	$ 133,211,009	$ 102,978,723	$ 133,824,885
		Theodore Roosevelt	$ 250,344,828	$ 135,069,767	$ 180,372,671
		Cumulative	**$ 20,625,000**	**$ 21,337,252**	**$ 17,224,199**
#3	OFA and Dry FGD #2 [3]	Boundary Waters	$ 92,980,392	$ 92,617,188	$ 51,655,773
		Voyageurs	$ 75,031,646	$ 129,562,842	$ 86,532,847
		Isle Royale	$ 89,135,338	$ 108,264,840	$ 69,327,485
		Badlands	$ 101,759,657	$ 76,731,392	$ 159,127,517
		Theodore Roosevelt	$ 185,234,375	$ 105,377,778	$ 98,381,743
		Cumulative	**$ 15,466,406**	**$ 15,588,429**	**$ 12,795,467**
#4	OFA and Wet FGD #2 [4]	Boundary Waters	$ 130,312,500	$ 108,513,011	$ 62,371,795
		Voyageurs	$ 93,858,521	$ 265,363,636	$ 131,486,486
		Isle Royale	$ 105,000,000	$ 114,023,438	$ 77,840,000
		Badlands	$ 128,590,308	$ 100,655,172	$ 123,164,557
		Theodore Roosevelt	$ 222,824,427	$ 127,467,249	$ 158,641,304
		Cumulative	**$ 19,140,984**	**$ 19,590,604**	**$ 15,617,978**
#5	SOFA and Dry FGD #1 [5]	Boundary Waters	$ 77,354,839	$ 67,170,868	$ 43,207,207
		Voyageurs	$ 66,611,111	$ 92,230,769	$ 66,611,111
		Isle Royale	$ 72,447,130	$ 88,487,085	$ 61,017,812
		Badlands	$ 84,734,392	$ 69,709,302	$ 85,642,857
		Theodore Roosevelt	$ 172,517,986	$ 92,230,769	$ 144,457,831
		Cumulative	**$ 13,411,633**	**$ 13,018,458**	**$ 11,045,601**
#5a	SOFA and Dry FGD #2 [6]	Boundary Waters	$ 74,753,086	$ 65,283,019	$ 41,331,058
		Voyageurs	$ 64,759,358	$ 90,373,134	$ 65,459,459
		Isle Royale	$ 70,406,977	$ 86,500,000	$ 59,217,604
		Badlands	$ 84,390,244	$ 69,597,701	$ 83,230,241
		Theodore Roosevelt	$ 165,890,411	$ 88,717,949	$ 133,812,155
		Cumulative	**$ 13,070,696**	**$ 12,727,273**	**$ 10,544,188**
#5b	SOFA and Wet FGD #2 [7]	Boundary Waters	$ 99,000,000	$ 77,545,692	$ 49,417,637
		Voyageurs	$ 78,364,116	$ 142,105,263	$ 89,728,097
		Isle Royale	$ 83,661,972	$ 95,498,392	$ 67,808,219
		Badlands	$ 106,834,532	$ 88,922,156	$ 102,768,166
		Theodore Roosevelt	$ 199,328,589	$ 106,451,613	$ 138,785,047

Option	Control Equipment	Class I Area	2002	2006	2007
		Cumulative	**$ 16,019,417**	**$ 15,730,932**	**$ 12,724,936**
#6	SNCR, SOFA, and Dry FGD #1 [8]	Boundary Waters	$ 73,048,128	$ 57,881,356	$ 39,536,903
		Voyageurs	$ 63,981,265	$ 78,959,538	$ 59,781,182
		Isle Royale	$ 66,960,784	$ 82,289,157	$ 58,626,609
		Badlands	$ 82,289,157	$ 71,331,593	$ 83,292,683
		Theodore Roosevelt	$ 179,736,842	$ 88,414,239	$ 135,920,398
		Cumulative	**$ 13,115,699**	**$ 12,262,118**	**$ 10,368,121**
#7	RRI, SNCR, SOFA, and Dry FGD #1 [9]	Boundary Waters	$ 79,450,801	$ 59,047,619	$ 42,187,120
		Voyageurs	$ 70,425,963	$ 83,261,391	$ 63,357,664
		Isle Royale	$ 71,293,634	$ 88,797,954	$ 65,386,064
		Badlands	$ 95,911,602	$ 83,662,651	$ 93,333,333
		Theodore Roosevelt	$ 210,424,242	$ 96,983,240	$ 143,471,074
		Cumulative	**$ 14,711,864**	**$ 13,467,804**	**$ 11,280,052**
#8	SCR, SOFA, and Dry FGD #1 [10]	Boundary Waters	$ 76,603,774	$ 55,871,560	$ 40,198,020
		Voyageurs	$ 68,044,693	$ 78,244,111	$ 60,798,669
		Isle Royale	$ 68,044,693	$ 85,174,825	$ 64,444,444
		Badlands	$ 97,962,466	$ 86,793,349	$ 91,122,195
		Theodore Roosevelt	$ 204,134,078	$ 93,933,162	$ 141,627,907
		Cumulative	**$ 14,329,412**	**$ 13,101,470**	**$ 10,900,955**

[1] – OFA and Dry FGD #1 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[2]- OFA and Wet FGD #1 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[3] - OFA and Dry FGD #2 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[4] - OFA and Wet FGD #2 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[5] – SOFA and Dry FGD #1 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[6] – SOFA and Dry FGD #2 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[7] – SOFA and Wet FGD #2 refers to separated over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[8] – SNCR, SOFA, and Dry FGD #1 refers to selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[9] - RRI, SNCR, SOFA, and Dry FGD #1 refers to rich reagent injection, selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units; and
[10] - SCR, SOFA, and Dry FGD #1 refers to selective catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units.

Based on the cost per deciview reduction numbers in Table 6-15, the most cost effective controls options are #5A, #6 and #8. The cost effective control costs are generally within 10 percent of each other.

6.3.5 BART Emissions Limits for Big Stone I

EPA identifies in 40 CFR Part 51, Appendix Y that in determining the "best" available retrofit technology, the state has discretion to determine the order in which the state should evaluate control options for BART. The state should provide a justification for adopting the technology that is selected as the ''best'' level of control, including an explanation of the Clean Air Act factors that led the state to choose that option over other control levels.

To complete the BART process, the state should establish enforceable emission limits that reflect the BART requirements and require compliance within a given period of time. In particular, the state should establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source. In addition, the state should require compliance with the BART emission limitations no later than five years after EPA approves South Dakota's State Implementation Plan for regional haze. If technological or economic limitations in the application of a measurement methodology to a particular emission unit make a conventional emissions limit infeasible, the state may instead prescribe a design, equipment, work practice, operation standard, or combination of these types of standards.

6.3.5.1 Particulate Matter BART Recommendation

Otter Tail Power Company already installed and is operating a baghouse, which is the top particulate control technology. Therefore, there is no additional compliance cost, energy impacts, etc. that Otter Tail Power Company would have to endure. As such, DENR considers the continual use of the baghouse as BART for particulate matter.

Otter Tail Power Company proposes an emission limit of 84.1 pounds per hour which they based on an emission rate of 0.015 pounds per million Btu and a maximum fuel heat input of 5,609 million Btus per hour. Otter Tail Power Company proposes to comply with the pounds per hour limit using a 30-day rolling average. Each day, Otter Tail Power Company will multiply the emission rate, in pounds per million Btus as determined by the most recent annual performance test, by the heat input to the boiler, as determined by a continuous emission monitoring system, and dividing by the number of hours the boiler operated that day.

In the December 11, 2006, application, Otter Tail Power Company proposed to replace the advanced hybrid particulate collector control system with the current day baghouse. In that application, Otter Tail Power Company noted that the baghouse would have a maximum filterable particulate matter emission rate of 0.012 pounds per million Btu of fuel heat input. The emission rate equates to 67.3 pounds per hour at 5,609 million Btus per hour heat input In May 2009, Otter Tail Power Company conducted a performance test on the baghouse. The test results noted an average filterable particulate matter emission rate of 0.011 pounds per million Btus and 57.6 pounds per hour.

DENR considers the emission limit representing BART as 67.3 pounds per hour. The hourly emission limit includes periods of startup and shutdown. DENR is also establishing a BART emission limit of 0.012 pounds per million Btus, which includes periods of startup and shutdown. Compliance with both emission limits shall be based on an annual stack performance test using the average of three 1-hour test runs.

6.3.5.2 Sulfur Dioxide BART Recommendation

Otter Tail Power Company is proposing the second ranked control option (semi-dry flue gas desulfurization system) to control sulfur dioxide emissions. Since control options #6, #7, and #8, which were the only three options that reduced the visibility less than the contribution level of 0.5 deciviews, did not include the top ranked sulfur dioxide control alternative an analysis of the visibility impacts of the other control alternatives was considered. Even though the top ranked control option (wet flue gas desulfurization system) reduces the sulfur dioxide emissions more than the second ranked control option, neither of the two control options is considered a better control option when considering the visibility impacts. For example, Table 6-16 displays the comparison of the visibility impacts for control option #3 to control option #4 and control option #5a to control option #5b. These options were chosen because the emission rates for nitrogen oxide and particulate matter were constant, while the sulfur dioxide emissions varied as noted by the two different control alternatives.

Table 6-16 – Visibility Comparison between Wet and Dry Scrubbers

	Control Option	Class I Area	2002	2006	2007
#3	OFA and Dry FGD #2 [1]	Boundary Waters	0.319	0.534	0.620
		Voyageurs	0.307	0.391	0.450
		Isle Royale	0.363	0.287	0.323
		Badlands	0.219	0.172	0.230
		Theodore Roosevelt	0.087	0.234	0.173
#4	OFA and Wet FGD #2 [2]	Boundary Waters	0.350	0.521	0.611
		Voyageurs	0.312	0.464	0.502
		Isle Royale	0.351	0.250	0.290
		Badlands	0.225	0.191	0.234
		Theodore Roosevelt	0.084	0.230	0.138
	Comparison Review	Boundary Waters	↑	↓	↓
		Voyageurs	↑	↑	↑
		Isle Royale	↓	↓	↓
		Badlands	↑	↑	↑
		Theodore Roosevelt	↓	↓	↓
#5a	SOFA and Dry FGD #2 [3]	Boundary Waters	0.250	0.419	0.493
		Voyageurs	0.249	0.306	0.354
		Isle Royale	0.285	0.226	0.256
		Badlands	0.165	0.133	0.180
		Theodore Roosevelt	0.069	0.186	0.141
#5b	SOFA and Wet FGD #2 [4]	Boundary Waters	0.274	0.407	0.478
		Voyageurs	0.244	0.365	0.393

	Control Option	Class I Area	2002	2006	2007
		Isle Royale	0.274	0.195	0.227
		Badlands	0.174	0.147	0.182
		Theodore Roosevelt	0.066	0.180	0.108
	Comparison Review	Boundary Waters	↑	↓	↓
		Voyageurs	↓	↑	↑
		Isle Royale	↓	↓	↓
		Badlands	↑	↑	↑
		Theodore Roosevelt	↓	↓	↓

[1] - OFA and Dry FGD #2 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[2] - OFA and Wet FGD #2 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[3] – SOFA and Dry FGD #2 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units; and
[4] – SOFA and Wet FGD #2 refers to separated over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units.

As noted in the table, approximately 40 percent of the modeling, the top ranked control option generated a higher visibility impact than the second ranked control option. Whereas, approximately 60 percent of the modeling, the second ranked control option generated a higher visibility impact than the top ranked control option. Therefore, based on the visibility modeling there is no discernable difference between these two control options. As such, DENR considers that the semi-dry flue gas desulfurization system is considered BART.

Otter Tail Power Company proposes an emission limit of 505 pounds per hour based upon a 30-day rolling average, which is based on the emission rate of 0.09 pounds per million Btu of fuel heat input at 5,609 million Btus per hour heat input.

The presumptive emission limit established by EPA for scrubber systems is 0.15 pounds per million Btus of fuel heat input. The limit proposed by Otter Tail Power Company is more stringent than the presumptive limit identified by EPA. DENR considers the emission limit representing BART should be 505 pounds per hour and 0.09 pounds per million Btus, which would include periods of startup, shutdown and malfunction. Compliance with these emission limits shall be based on the continuous emission monitoring system and on a 30-day rolling average.

6.3.5.3 Nitrogen Oxide BART Recommendation

Otter Tail Power Company is proposing the fourth ranked control option (separated over-fire air) to control nitrogen oxide emissions. In reviewing the higher ranked control options, each option reduces the amount of nitrogen oxide emissions and the visibility impacts more than the fourth ranked control option (separated over-fire air). However, each of these higher ranking control options comes with a higher financial cost.

In establishing the nitrogen oxide presumptive BART requirements, EPA identified that $1,500 per ton of nitrogen oxide removed was considered cost effective. (Federal Register Volume 70 Number 128 on pages 39134 and 39135). EPA considers this threshold cost effective for a coal fired unit greater than 200 megawatts existing at a facility with a combined capacity greater than 750 megawatts.

Otter Tail Power Company's Big Stone I facility does not have a capacity greater than 750 megawatts and is not applicable to the established nitrogen oxide presumptive BART requirements. However, Otter Tail Power Company's Big Stone I's coal fired unit is greater than the 200 megawatt. As noted in Table 6-10, the cost of the control options on a $ per ton basis are all less than $900 per ton. As such DENR considers all the identified control options as cost effective on a $ per ton basis.

As noted in Table 6-15, the cost on a $ per deciview basis indicates that control options #5a, #6 and #8 are the most cost effective. Options #5a, #6 and #8 consider the operation of separated over-fire air, selective non catalytic reduction and selective catalytic reduction. It should be noted that the $ per deciview includes the cost for both sulfur dioxide and nitrogen oxide.

As noted in Table 6-14, control options #6, #7, #8, were the only options that resulted in modeling less than 0.5 deciviews of visibility impairment. Again, it should be noted the modeling results includes the emissions of particulate matter, sulfur dioxide, and nitrogen oxide.

None of the nitrogen oxide control alternatives have identified energy, non-air environmental, or have issues with the current life expectancy of the Big Stone I coal fire unit to preclude the use of any of the control options. As such DENR considers all the identified control options as being acceptable options based on impacts to energy, non-air environmental and life expectancy.

Based on the visibility modeling, the first ranked control option (selective catalytic reduction) reduces the visibility more than any other control option. The selective catalytic reduction system also reduces the visibility an additional 34 percent over the second ranked control option and an additional 65 percent over the fourth ranked control option. The selective catalytic reduction is also considered cost effective on a $ per ton basis, is represented as part of the control option #8 that is one of the most cost effective options on a $ per deciview reduction basis and one of the options that modeling demonstrates less than 0.5 deciviews of visibility impairment. DENR considers selective catalytic reduction and separate over-fire air system as BART.

The presumptive emission limit established by EPA for a selective catalytic reduction system installed on a cyclone coal fired unit is 0.10 pounds per million Btus of fuel heat input (Federal Register Volume 70 Number 128 on page 39172). DENR considers the emission limit representing BART should be 561 pounds per hour and 0.10 pounds per million Btus, which would include periods of startup, shutdown and malfunction. Compliance with the emission limits shall be based on the continuous emission monitoring system and on a 30-day rolling average.

6.4 BART Requirements

Otter Tail Power Company's Big Stone I reasonably contributes to visibility impairment at Class I areas and is considered a BART-eligible source subject to BART. Therefore, DENR is adopting BART requirements in its Administrative Rules of South Dakota under Chapter 74:36:21 – Regional Haze Program.

These requirements will be part of South Dakota's Regional Haze State Implementation Plan and will be enforceable because they will establish emission limits representing BART; in accordance with 40 CFR § 51.308(e)(1)(v), the BART control equipment will be required to be properly operated and maintained; and testing, monitoring, recordkeeping, and reporting requirements will be established to ensure compliance with BART. One method of determining if control equipment is being properly operated and maintained is through monitoring the emissions from the unit. In Otter Tail Power Company's case, continuous emission monitoring sulfur dioxide and nitrogen oxide is already required in their existing permit. The minimum requirements for the operation, maintenance, and monitoring requirements will be established in ARSD 74:36:21:07. In accordance with 40 CFR § 51.308(e)(1)(iv), DENR will require BART to be installed and operating as expeditiously as practicable, but no later than 5 years from EPA's approval of South Dakota's Regional Haze Program. The deadline for installing BART will be established in ARSD 74:36:21:06.

In accordance with 40 CFR § 51.308(e)(5), once the requirements of BART are achieved, Otter Tail Power Company will be subject to the requirements of South Dakota's State Implementation Plan in the same manner as other sources.

7.0 Reasonable Progress

In accordance with 40 CFR § 51.308(d)(1), for each mandatory Class I area located within the state, the state must establish goals, expressed in deciviews, that provide reasonable progress towards achieving natural visibility conditions by 2064. The reasonable progress goals must provide improvement in visibility for the 20% most impaired days over the period of the implementation plan and ensure no degradation in visibility for the 20% least impaired days over the same period. In accordance with 40 CFR § 51.308(d)(1)(v), the reasonable progress goals established by the state are not directly enforceable but will be considered in the evaluation of the adequacy of the measures a state would implement to achieve natural conditions by 2064. In accordance with 40 CFR § 51.308(d)(1)(vi), the state may not adopt a reasonable progress goal that represents less visibility improvement than is expected to result from implementation of other requirements of the federal Clean Air Act during the applicable planning period.

The EPA published the *Guidance for Setting Reasonable Progress Goals under the Regional Haze Rule, 2007*, for setting reasonable progress goals. The basic steps include:

1. Establish baseline and natural visibility conditions;
2. Determine the glide path or uniform rate of progress;
3. Identify and analyze the measures aimed at achieving the uniform rate of progress using the following approaches:

ARTICLE 74:36

AIR POLLUTION CONTROL PROGRAM

Chapter

CHAPTER 74:36:21

REGIONAL HAZE PROGRAM

Section

74:36:21:12 Federal land manager notification and review.

74:36:21:02. Definitions. Unless otherwise specified, the terms used in this chapter mean:

(1) "Adverse impact on visibility," visibility impairment that interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the mandatory Class I federal area. Adverse impact on visibility shall be based on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency, and time of visibility impairment, and how these factors correlate with times of visitor use of a mandatory Class I federal area and the frequency and timing of natural conditions that reduce visibility;

(2) "BART," best available retrofit technology;

(3) "Best available retrofit technology" an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant that is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility that may reasonable be anticipated to result from the use of such technology;

(4) "BART-eligible source," an existing stationary facility;

(5) "Coal-fired power plant," any person, corporation, limited liability company, association, company, partnership, political subdivision, municipality, rural electric cooperative, consumers power district, or any group or combination acting as a unit, owning or holding under

lease, or otherwise real property used, or intended for use, for the conversion of coal into electric power;

(6) "Contribute to adverse impact on visibility," a change in visibility impairment in a mandatory Class I federal area of five-tenths deciviews or more, based on a 24-hour average, above the average natural visibility baseline. A source exceeds the threshold if the 98th percentile (eighth highest value) of the modeling results, based on one year of the three years of meteorological data modeled, equals or exceeds five-tenths deciviews;

(7) "Major source," as defined in § 74:36:01:08(2) and (3);

(8) "Mandatory Class I federal area," any area identified in 40 C.F.R. § 81, Subpart D (July 1, 2009); ~~and~~

(9) "Visibility impairment," any human perceptible change in visibility such as light extinction, visual range, contrast, coloration, from that which would have existed under natural conditions; and

(10) "30-day rolling average," shall be expressed as pounds per million Btus and pounds per hour and calculated in accordance with the following procedures:

(a) Sum the total pounds of pollutant in question emitted from a unit during an operating day and the previous 29 operating days;

(b) Sum the total heat input to the unit in million Btus during the operating day and the previous 29 operating days;

(c) Sum the total hours the unit operated in hours during the day and the previous 29 operating days;

(d) For pounds per million Btus, divide the total number of pounds of the pollutant emitted during the 30-day operating days by the total heat input during the 30-day operating days;

(e) For pounds per hour, divide the total number of pounds of the pollutant emitted during the 30-day operating days by the total hours operated during the 30-day operating days. A new 30-day rolling average shall be calculated for each new operating day. Each 30-day rolling average shall represent all emissions, including emissions that occur during periods of startup, shutdown and malfunction.

(11) "Operating day," means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted the entire 24-hour period.

Source: 37 SDR 111, effective December 7, 2010.

General Authority: SDCL 34A-1-6.

Law Implemented: SDCL 34A-1-6.

74:36:21:06. BART determination for a BART-eligible coal-fired power plant. The owner or operator of a BART-eligible coal-fired power plant may not cause or permit emissions of the following regulated air pollutant in excess of the following amounts:

(1) PM10 emissions in excess of 67.3 pounds per hour, which includes periods of startup and shutdown;

(2) PM10 emissions in excess of 0.012 pounds per million Btus, which includes periods of startup and shutdown;

(3) Sulfur dioxide emissions in excess of 505 pounds per hour, which includes periods of startup, ~~and~~ shutdown, and malfunction;

(4) Sulfur dioxide emissions in excess of 0.09 pounds per million Btus, which ~~does not include~~ includes periods of startup, ~~and~~ shutdown, and malfunction;

(5) Nitrogen oxide emissions in excess of 561 pounds per hour, which includes periods of startup, ~~and~~ shutdown, and malfunction; and

(6) Nitrogen oxide emissions in excess of 0.10 pounds per million Btus, which ~~does not include~~ includes periods of startup, ~~and~~ shutdown, and malfunction.

Compliance with the PM10 emission limits shall be based on an annual stack performance test using the performance testing methods in § 74:36:11:01 and using the average of three 1-hour test runs. Compliance with the sulfur dioxide and nitrogen oxide emission limits shall be based on using continuous emission monitoring systems and a 30-day rolling average.

Source: 37 SDR 111, effective December 7, 2010.

General Authority: SDCL 34A-1-6.

Law Implemented: SDCL 34A-1-6.

74:36:21:09. Monitoring, recordkeeping, and reporting. The owner or operator required to install and operate controls established in a visibility impact analysis or BART determination shall conduct periodic monitoring, recordkeeping, and reporting. All sulfur dioxide and nitrogen oxides emissions from the BART-eligible source shall be routed to the main stack of a BART-eligible source. ~~Monitoring of sulfur dioxide and nitrogen oxide emissions from the main stack shall be conducted using a continuous emission monitoring system which complies with the continuous emission monitoring requirements in chapter 74:36:13.~~ The owner or operator of a BART-eligible source shall install, certify, maintain, calibrate and operate a continuous emission monitoring system for sulfur dioxide and nitrogen oxide in accordance with 40 C.F.R. Part 75 (July 1, 2009), except the recordkeeping and reporting requirements for the continuous emission monitoring systems shall be in accordance with 40 C.F.R. § 60.7 (July 1, 2009).

Monitoring and related recordkeeping and reporting requirements for other air pollutants from a BART-eligible source or from a major source or modification of a major source shall consist of at least the following: ~~be in accordance with § 74:36:05:16.01(9). Recordkeeping and reporting shall comply with the requirements in § 74:36:05:16.01(9)~~.

(1) All emissions monitoring and analysis procedures, alternative approved methods or test methods required in determining compliance with §§ 74:36:21:04 and 74:36:21:06;

(2) As necessary, documentation of the use, maintenance, and if appropriate, installation of monitoring equipment or methods;

(3) Documentation of the following:

(a) The date, place, and time of sampling or measurements;

(b) The date or dates analyses were performed;

(c) The company or entity that performed the analyses;

(d) The analytical techniques or methods used;

(e) The results of such analyses; and

(f) The operating conditions as existing at the time of sampling or measurement;

(4) Recordkeeping and reporting requirements that comply with the following:

(a) Submission of reports of any required monitoring must occur at least every six months. Reports must clearly identify all exceedances with §§ 74:36:21:04 and 74:36:21:06. All required reports must be certified by a responsible official; and

(b) Exceedances of §§ 74:36:21:04 and 74:36:21:06, including those attributable to upset conditions, the probable cause of such exceedance and any corrective actions or preventive measures taken must be promptly reported and certified by a responsible official; and

(5) Requirements for retention of monitoring records and all supporting documentation for at least five years from the date of the monitoring sample, measurement, report, or application.

Source: 37 SDR 111, effective December 7, 2010.

General Authority: SDCL 34A-1-6.

Law Implemented: SDCL 34A-1-6.