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ATTACHMENT 8

NATURAL GAS CONVERSION CONCEPTUAL STUDY

Docket No.
PU-11-163/ PU-11-165

OTP/MDU-109

Sargent & Lundy LLC

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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

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

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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

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KENNETH A. MIXER
SOUTH DAKOTA

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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.

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- 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.

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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

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[1] SO_2, NO_X, and Mercury Reduction Study, *Conceptual Engineering Study Report*, Draft SL-010408, September 24, 2010.

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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.

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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.

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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 ≤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.

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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.

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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.

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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 maximum hourly emissions 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)).

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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.

TRADE SECRET DATA ENDS]

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

Pollutant	Proposed BART Emission Limits lb/mmBtu	Proposed BART Emission Limits 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

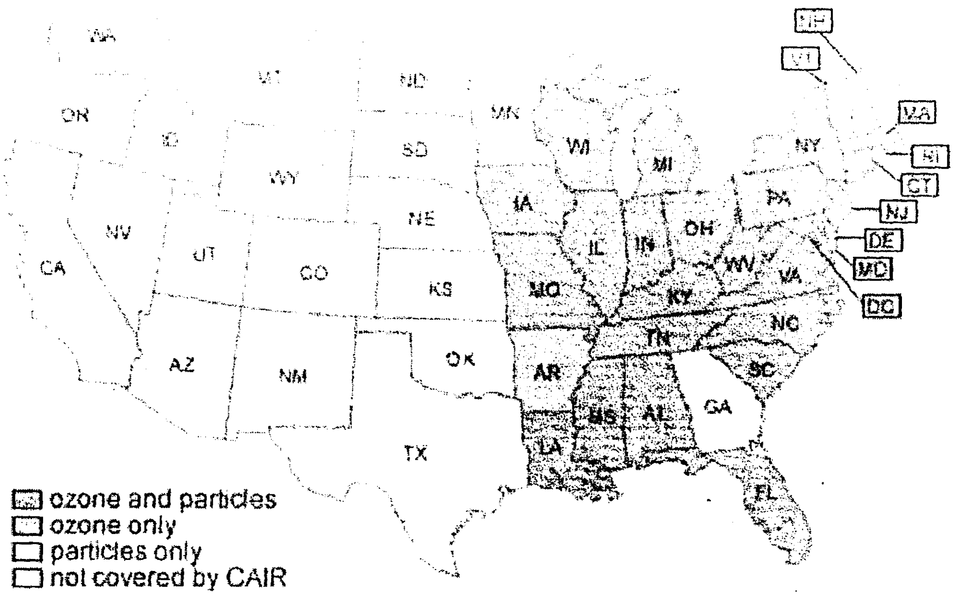
	Projected Annual SO_2 Emissions (tpy)	ARP Annual SO_2 Allowances (tpy)	
[TRADE SECRET DATA BEGINS		12,973	TRADE SECRET DATA ENDS]

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.

[TRADE SECRET DATA BEGINS

- 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)	

TRADE SECRET DATA ENDS]

[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.
TRADE SECRET DATA ENDS]

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
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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.

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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]