Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in South Dakota

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Revised Draft Report

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Scope of Document

This document provides an initial analysis of the four factors which must be considered in establishing a reasonable progress goal toward achieving natural visibility conditions in mandatory Class I areas. These factors were examined for several candidate control measures for priority pollutants and emission sources. The results of this report are intended to inform policymakers in setting reasonable progress goals for the Class I areas in the Western Regional Air Partnership (WRAP) region.

This document does not address policy issues, set reasonable progress goals, or recommend a long-term strategy for regional haze. Separate documents will be prepared by the States which address the reasonable progress goals, each state's share of emission reductions, and coordinated emission control strategies.

Disclaimer

The analysis described in this document has been funded by the Western Governors' Association. It has been subject to review by the WGA and the WRAP. However, the report does not necessarily reflect the views of the sponsoring and participating organizations, and no official endorsement should be inferred.

Contents

Abbreviations

BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CO_2	Carbon Dioxide
EC	Elemental Carbon
EDMS	Emissions Data Management System
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
FGD	Flue Gas Desulfurization
ICAC	Institute of Clean Air Companies
LNB	Low-NOx Burners
MW	Megawatt
NACAA	National Association of Clean Air Agencies
NEI	National Emissions Inventory
NO_x	Nitrogen Oxides
OC	Organic Carbon
OFA	Overfire Air
PM	Particulate Matter
PM_{10}	Particulate Matter Particles of 10 Micrometers or Less
$PM_{2.5}$	Particulate Matter Particles of 2.5 Micrometers or Less
SCR	Selective Catalytic Reduction
SNCR	Selective Noncatalytic Reduction
SO_2	Sulfur Dioxide
VOC	Volatile Organic Compounds
WRAP	Western Regional Air Partnership

1. Introduction

The Regional Haze Rule requires States to set reasonable progress goals toward meeting a national goal of natural visibility conditions in Class I areas by the year 2064. The first reasonable progress goals will be established for the planning period 2008 to 2018. The Western Regional Air Partnership (WRAP), along with its member states, tribal governments, and federal agencies, are working to address visibility impairment due to regional haze in Class I areas. The Regional Haze Rule identifies four factors which should be considered in evaluating potential emission control measures to meet visibility goals. These are as follows:

1. Cost of compliance
2. Time necessary for compliance
3. Energy and non-air quality environmental impacts of compliance
4. Remaining useful life of any existing source subject to such requirements

This report has been prepared as part of a project to evaluate the above factors for possible control strategies intended to improve visibility in the WRAP region. We have identified control measures for emissions of nitrogen oxides (NO_X) and sulfur dioxide (SO_2), which can react in the atmosphere to produce visibility-obscuring particulate matter on a regional scale, and also for direct emissions of particulate matter. For direct particulate matter (PM) emissions, we have evaluated the impacts of control measures on various particulate matter components, including $PM_{2.5}$, PM_{10}, elemental carbon (EC) particulate matter, and organic carbon (OC) particulate matter. A number of emission source categories have been addressed, including:

1. Reciprocating internal combustion engines and turbines
2. Oil and natural gas exploration and production field operations
3. Natural gas processing plants
4. Industrial boilers
5. Cement manufacturing plants
6. Sulfuric acid manufacturing plants
7. Pulp and paper plant lime kilns
8. Petroleum refinery process heaters

The four-factor analyses for these emission categories are documented in a separate report, entitled "Assessing Reasonable Progress for Regional Haze in the WRAP Region – Source Category Analysis."

The current report presents the results of a four-factor analysis of potential control measures for selected emission sources including one electric generating unit and two cement kilns at one cement manufacturing plants in South Dakota. The emission sources addressed in this current report were selected by the South Dakota Department of Environment and Natural Resources. Section 2 presents the methodology employed for the analyses, Section 3 presents the results of the four-factor analysis for boilers and Section 4 presents the results for cement kilns.

2. Methodology

The first step in the technical evaluation of control measures for a source category was to identify the major sources of emissions from the category. Emissions assessments were initially based on 2002 emissions inventory in the WRAP Emissions Data Management System (EDMS),[1] which consists of data submitted by the WRAP states in 2004. The states then reviewed the emissions data and parameters from the EDMS used for this analysis and provided updated data when applicable. In some cases, detailed data on PM_{10} and $PM_{2.5}$ emissions were not available from the WRAP inventory. Therefore, PM_{10} and $PM_{2.5}$ data from the U.S. Environmental Protection Agency's (EPA) 2002 National Emissions Inventory (NEI) were used to supplement the WRAP inventory where necessary.

Once the important emission sources were identified within a given emission source category, a list of potential additional control technologies was compiled from a variety of sources, including control techniques guidelines published by the EPA, emission control cost models such as AirControlNET[2] and CUECost,[3] Best Available Retrofit Technology (BART) analyses, White Papers prepared by the Midwest Regional Planning Organization (MRPO),[4] and a menu of control options developed by the National Association of Clean Air Agencies (NACAA).[5] The options for each source category were then narrowed to a set of technologies that would achieve the emission reduction target under consideration. The following sections discuss the methodology used to analyze each of the regional haze factors for the selected technologies.

2.1 Factor 1 – Costs

Control costs include both the capital costs associated with the purchase and installation of retrofit and new control systems, and the net annual costs (which are the annual reoccurring costs) associated with system operation. The basic components of total capital costs are direct capital costs, which includes purchased equipment and installation costs, and indirect capital expenses. Direct capital costs consist of such items as purchased equipment cost, instrumentation and process controls, ductwork and piping, electrical components, and structural and foundation costs. Labor costs associated with construction and installation are also included in this category. Indirect capital expenses are comprised of engineering and design costs, contractor fees, supervisory expenses, and startup and performance testing. Contingency costs, which represent such costs as construction delays, increased labor and equipment costs, and design modification, are an additional component of indirect capital expenses. Capital costs also include the cost of process modifications. Annual costs include amortized costs of capital investment, as well as costs of operating labor, utilities, and waste disposal. For fuel switching options, annual costs include the cost differential between the current fuel and the alternate fuel.

The U.S. EPA's *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program*[6] indicates that the four-factor analyses should conform to the methodologies given in the *EPA Air Pollution Control Cost Manual*.[7] This study draws on cost analyses which have followed the protocols set forth in the Cost Manual. Where possible, we have used the primary references for cost data. Cost estimates have been updated to 2007 dollars using the Marshall & Swift Equipment Cost Index or the Chemical Engineering Plant Cost Index, both of which are published in the journal, *Chemical Engineering.*

For Factor 1, results of the cost analysis are expressed in terms of total cost-effectiveness, in dollars per ton of emissions reduced. A relevant consideration in a cost-effectiveness calculation is the economic condition of the industry (or individual facility if the analysis is performed on that basis). Even though a given cost-effectiveness value may, in general, be considered "acceptable," certain industries may find such a cost to be overly burdensome. This is particularly true for well-established industries with low profit margins. Industries with a poor economic condition may not be able to install controls to the same extent as more robust industries. A thorough economic review of the source categories selected for the factor analysis is beyond the scope of this project.

2.2 Factor 2 – Time Necessary for Compliance

For Factor 2, we evaluated the amount of time needed for full implementation of the different control strategies. The time for compliance was defined to include the time needed to develop and implement the regulations, as well as the time needed to install the necessary control equipment. The time required to install a retrofit control device includes time for capital procurement, device design, fabrication, and installation. The Factor 2 analysis also included the time required for staging the installation of multiple control devices at a given facility.

2.3 Factor 3 – Energy and Other Impacts

Table 2-1 summarizes the energy and environmental impacts analyzed under Factor 3. We evaluated the direct energy consumption of the emission control device, solid waste generated, wastewater discharged, acid deposition, nitrogen deposition, and climate impacts (e.g., generation and mitigation of greenhouse gas emissions).

In general, the data needed to estimate these energy and other non-air pollution impacts were obtained from the cost studies which were evaluated under Factor 1. These analyses generally quantify electricity requirements, steam requirements, increased fuel requirements, and other impacts as part of the analysis of annual operation and maintenance costs.

Costs of disposal of solid waste or otherwise complying with regulations associated with waste streams were included under the cost estimates developed under Factor 1, and were evaluated as to whether they could be cost-prohibitive or otherwise negatively affect the facility. Energy needs and non-air quality impacts of identified control technologies were aggregated to estimate the energy impacts for the specified industry sectors. However, indirect energy impacts were not considered, such as the different energy requirements to produce a given amount of coal versus the energy required to produce an equivalent amount of natural gas.

Table 2-1 Summary of Energy and Environmental Impacts Evaluated Under Factor 3

Energy Impacts
Electricity requirement for control equipment and associated fans
Steam required
Fuel required
Environmental Impacts
Waste generated
Wastewater generated
Additional carbon dioxide (CO_2) produced
Reduced acid deposition
Reduced nitrogen deposition
Benefits from reductions in $PM_{2.5}$ and ozone, where available
Impacts Not Included
Impacts of control measures on boiler efficiency
Energy required to produce lower sulfate fuels
Secondary environmental impacts to produce additional energy (except CO_2) produced

2.4 Factor 4 – Remaining Equipment Life

Factor 4 accounts for the impact of the remaining equipment life on the cost of control. Such an impact will occur when the remaining expected life of a particular emission source is less than the lifetime of the pollution control device (such as a scrubber) that is being considered. In this case, the capital cost of the pollution control device can only be amortized for the remaining lifetime of the emission source. Thus, if a scrubber with a service life of 15 years is being evaluated for a boiler with an expected remaining life of 10 years, the shortened amortization schedule will increase the annual cost of the scrubber.

The ages of major pieces of equipment were determined where possible, and compared with the service life of pollution control equipment. The impact of a limited useful life on the amortization period for control equipment was then evaluated, along with the impact on annualized cost-effectiveness.

2.5 References for Section 2

1. WRAP (2008), *Emissions Data Management System*, Western Regional Air Partnership, Denver, CO, http://www.wrapedms.org/app_main_dashboard.asp.

2. E.H. Pechan & Associates (2005), *AirControlNET, Version 4.1 - Documentation Report*, U.S. EPA, RTP, NC, http://www.epa.gov/ttnecas1/AirControlNET.htm.

3. *Coal Utility Environmental Cost (CUECost) Model Version 1.0*, U.S. EPA, RTP, NC, http://www.epa.gov/ttn/catc/products.html.

4. MRPO (2006), *Interim White Papers-- Midwest RPO Candidate Control Measures*, Midwest Regional Planning Organization and Lake Michigan Air Directors Consortium, Des Plaines, IL, www.ladco.org/reports/control/white_papers/.

5. NACAA (formerly STAPPA and ALAPCO) (2006), *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, National Association of Clean Air Agencies, www.4cleanair.org/ PM25Menu-Final.pdf.

6 EPA (2007), *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program*, http://www.epa.gov/ttncaaa1/t1/memoranda/reasonable_progress_guid071307.pdf.

7. EPA (2002), *EPA Air Pollution Control Cost Manual*, *6th ed.*, EPA/452/B-02-001, U.S. EPA, Office of Air Quality Planning and Standards, RTP, NC, Section 5 - SO_2 and Acid Gas Controls, pp 1-30 through 1-42, http://www.epa.gov/ttncatc1/products.html#cccinfo.

3. Boilers

A four-factor analysis was performed on a single coal-fired boiler at Black Hill Power and Light Company – Ben French Station. This boiler is used to produce steam from the combustion of sub-bituminous coal to generate electricity in a steam turbine. The unit at BEN French Station is rated at 25 megawatts (MW). Pollutant emissions from the boilers include: nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM).

Table 2-1 summarizes the NO_X and SO_2 emissions from the boiler, as well as the control measures used to reduce these pollutant emissions.[1] The pollutant emission rates shown in Table 2-1 were obtained from the WRAP 2002 emission inventory.[2] Emissions of EC and OC can be estimated using speciation factors from EPA's SPECIATE database.[3] The EC and OC components are estimated to comprise 0.021% and 0.012% of PM_{10} emissions from coal-fired boilers, respectively.

Table 3-1. Emissions from Selected Boilers - South Dakota

Source Name	Facility Name	Unit ID	Unit Type	Boiler Size (MW)	NO_X Annual Emissions (tons/yr)	SO_2 Annual Emissions (tons/yr)	Annual Emission Date
Black Hills Power and Light Co.	Ben French Station	Unit 1	Sub-bituminous coal-fired boiler	25	907.5	785.0	2002

Currently, the boiler at the Ben French Station is uncontrolled. The facility does utilize a low sulfur coal (0.33 wt %) to minimize the formation of SO2 during the combustion process. A list of potential NO_X and SO_2 control strategies are presented in Table 2-2. The table provides a range of pollutant reductions and presents the potential emission reductions from the baseline emissions by applying the listed control options.[4,5] These control options have been applied to many electrical generating unit boilers in the U.S. to reduce emissions of NO_X and SO_2.

Table 3-2. Control Options for Selected Boilers - South Dakota

Facility Name	Source Type	Pollutant controlled	Control Technology	Baseline emissions[1] (tons/yr)	Estimated control efficiency (%)	Potential controlled emissions[2] (tons/yr)
Ben French Station - Unit 1	Sub-bitiminous coal-fired boiler	NO_X	LNB	907	30 - 75	681
			LNB w/OFA		50 - 65	590
			SNCR		30 - 75	681
			SCR		40 - 90	817
		SO_2	Dry sorbent injection	785	10 - 40	314
			Spray dryer absorber		90	706
			Wet FGD		90	706

[1] Baseline emissions obtained from 2002 EDMS database.

[2] Potential emission reductions calculated using the highest percentage in the estimated control efficiency range.

3.1 Factor 1 – Costs

Table 2-3 provides cost estimates for the emission control options which have been identified for each of the electrical generating unit boilers. For each option, the table gives an estimate of the capital cost to install the necessary equipment, and the total annual cost of control, including the amortized cost associated with the capital equipment cost. The capital cost values are expressed in terms of the cost per MW size of the boiler using EPA cost information.[6,7] The capital cost data was extrapolated to determine the capital cost for the larger sized boilers. The annual cost was calculated by amortizing the capital cost over 30 years at an interest rate of 7% and multiplying that value by an O&M factor. Table 2-3 also estimates the cost effectiveness for each control measure, in terms of the cost per ton of emission reduction. Recent literature[8] has indicated that the cost of SCR for electric generating can vary from $120 to $170 per kilowatt, therefore due to this variability, the capital and annual costs for SCR are presented as a range.

3.2 Factor 2 – Time Necessary for Compliance

Once a State decides to adopt a particular control strategy, up to 2 years will be needed to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. The Institute of Clean Air Companies (ICAC) has estimated that approximately 18 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control, and approximately 30 months to design, build, and install SO_2 scrubbing technology.[9] Additional time of up to 12 months may be required for staging the installation process if multiple boilers are to be controlled at a single facility. Based on these figures, the total time required to achieve emission reductions for industrial boilers is estimated at a total of 5½ years for NO_X strategies, and 6½ years for SO_2 strategies.

Table 3-3. Estimated Costs of Control for Selected Boilers - South Dakota

Facility Name	Pollutant controlled	Control Technology	Estimated control efficiency (%)	Estimated capital cost ($1000)	Estimated annual cost ($1000/yr)	Cost effectiveness ($/ton)
Ben French Station - Unit 1	NO_X	LNB	51	1,250	195	421
		LNB w/OFA	65	1,780	298	505
		SNCR	40	1,290	770	2,121
		SCR	80	3,000 - 4,250	754 - 1,068	1,039 - 1,471
	SO_2	Dry sorbent injection	40	4,300	1,700	5,414
		Spray dryer absorber	90	11,600	2,670	3,779
		Wet FGD	90	14,600	2,760	3,907

[1] The annual cost was calculated using a 30-year equipment life and 7% interest.

[2] Cost effectiveness calculated from baseline emissions using the estimated control efficiency.

3.3 Factor 3 – Energy and Other Impacts

Table 2-4 shows the estimated energy and non-air pollution impacts of control measures for industrial boilers. The values were obtained from an EPA report listing the performance impacts of each of the control technology options.[10,11] In general, the combustion modification technologies (LNB, OFA) do not require steam or generate solid waste, or wastewater. They also do not require additional fuel to operate, and in some cases may decrease fuel usage because of the optimized combustion of the fuel.

Retrofitting of a SNCR requires energy for compressor power and steam for mixing. This would produce a small increase in CO_2 emissions to generate electricity; however the technology itself does not produce additional CO_2 emissions.

Installation of SCR on an industrial boiler is not expected to increase fuel consumption. However additional energy is required to operate the SCR, which will produce an increase in CO_2 emissions to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal. However, many catalyst companies accept the return of spent catalyst material.

Retrofitting of the SO_2 control options increase the usage of electricity, and produce both a solid waste and wastewater stream. In addition, increases of CO_2 emissions will occur due to the increased energy usage for material preparation (e.g., grinding), materials handling (e.g., pumps/blowers), flue gas pressure loss, and steam requirements. Power consumption is also affected by the reagent utilization of the control technology, which also affects the control efficiency of the control technology.

Table 3-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Selected Boilers - South Dakota

Source Type	Control Technology	Pollutant controlled	Energy and non-air pollution impacts: Electricity requirement (kW)	Steam requirement (lb/hr)	Solid waste produced (ton/hr)	Wastewater produced (gal/min)	Additional CO_2 emitted (tons/yr)
Ben French Station - Unit 1	LNB	NO_X	1.2				0.0012
	LNB w/OFA	NO_X	1.2				0.0012
	SNCR	NO_X	7	170			0.007
	SCR	NO_X	181	204			0.18
	Dry sorbent injection	SO_2	265		1.5	18.3	0.3
	Spray dryer absorber	SO_2	183		1.8	14.7	0.18
	Wet FGD	SO_2	524		1.5	33	0.5

NOTES:
A blank cell indicates no impact is expected.

3.4 Factor 4 – Remaining Equipment Life

Electric generating units do not have a set equipment life. Since many of the strategies are market-based reductions applied to geographic regions, it is assumed that control technologies will not be applied to units that are expected to be retired prior to the amortization period for the specific control equipment. Therefore, the remaining life of an industrial boiler is not expected to affect the cost of control technologies for industrial boilers.

3.5 References for Section 3

1. NEEDS 2006.

2. WRAP(2008), *Emissions Data Management System, Western Regional Air Partnership*, Denver, CO. http://www.wrapedms.org/app_main_dashboard.asp

3. EPA (2006), *SPECIATE version 4*, U.S. EPA, RTP, NC. http://www.epa.gov/ttn/chief/software/speciate/index.html

4. MRPO (2006), *Interim White Paper - Midwest RPO Candidate Control Measures Source Category: Industrial, Commercial, and Institutional (ICI) Boilers*. http://www.ladco.org/reports/control/white_papers/

5. NESCAUM (2009), *Applicability and Feasibility of NO_X, SO_2, and PM Emission Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers*.

6. Khan, Sikander (2003), *Methodology, Assumptions, and References: Preliminary NO_X Controls Cost Estimates for Industrial Boilers*.

7. Khan, Sikander (2003), *Methodology, Assumptions, and References: Preliminary SO2 Controls Cost Estimates for Industrial Boilers*.

8. Power Magazine (2006), *Estimating SCR Installation Costs*. http://www.powermag.com/instrumentation_and_controls/Estimating-SCR-installation-costs_506_p3.html

9. Institute of Clean Air Companies (2006), *Typical Installation Timelines for NO_X missions Control Technologies on Industrial Sources*.

10. Reference 6.

11. Reference 7.

4. Cement Manufacturing

Four-factor analyses have been conducted for selected emission sources at one South Dakota cement manufacturing plant. The following facility and emission sources have been evaluated:

- GCC Dacotah, Rapid City Plant – Cement Kilns #4 and #5

Table 3-1 outlines the baseline levels of emissions and potential additional control measures that could be adopted to further reduce emissions. The table also gives the estimated control efficiency and annual emission reduction for each potential future control measure.

Baseline emissions of NO_X and SO_2 for the refineries were obtained from the WRAP 2002 emissions inventory.[1] Emissions of $PM_{2.5}$ and PM_{10} were obtained from the 2002 U.S. EPA NEI and from the state of South Dakota.[2] Emissions of EC and OC were estimated using speciation factors from EPA's SPECIATE database.[3] EC and OC are estimated to comprise 0.07% and 0.014% of PM_{10} emissions from cement kilns, respectively.

The primary source of emissions from cement manufacturing plants is the cement kiln. There are four types – long wet kilns, long dry kilns, preheater kilns, and preheater/precalciner kilns. Fuels used in cement kilns include coal, natural gas, and waste-derived fuels (primarily scrap tires, but also motor oils, surplus printing inks, and sludge from the petroleum industry).[4]

Wet, long dry, and most preheater kilns have one fuel combustion zone; newer preheater/precalciner kilns have two fuel combustion zones and some may even have three. NO_X emissions are generated due to oxidation of molecular nitrogen present in the combustion air (i.e., thermal NO_X formation) or oxidation of nitrogen compounds within the combustion fuel (i.e., fuel NO_X formation). The temperature within the combustion zone(s) dictate, in part, the amount of NO_X formed during the production of clinker. The energy efficiency also dictates the formation of emissions, as the efficiency influences the amount of heat input required to produce cement.[5] SO_2 emissions are created from sulfur compounds in the raw materials used (i.e., limestone, clay, sand and iron ore) and to a smaller extent in the fuel.[4] PM emissions are also generated by cement kilns.

Table 4-1. Existing Control Measures and Potential Additional Control Options for Selected Cement Manufacturing Operations

Company	Source	Pollutant	Baseline emissions (tons/yr)	Existing Control Technology	Potential Control Technology	Estimated control efficiency (%)	Potential emission reduction (tons/year)	References
GCC Dacotah, Rapid City Plant	Long Wet Kiln # 4	NO_X	707	None	LNB (indirect)	30-40	212 - 283	5,11,15,19
					LNB (direct)	40	283	5,11,15,19
					Biosolid Injection	23	163	5,11,15,19
					CemSTAR	20-60	14 - 424	5,11,15,19
					Mid-Kiln	20-50	14 - 353	5,11,15,19
					SCR	80	565	10,11,14,15
		SO_2	26	None	Wet FGD	90-99	24 - 26	10,11,14,15
		PM_{10}	136	Dry ESP	Fabric Filter	99	134	10,11,14,15
		$PM_{2.5}$	67	Dry ESP	Fabric Filter	99	67	10,11,14,15
		EC	10	Dry ESP	Fabric Filter	99	9.38	10,11,14,15
		OC	2	Dry ESP	Fabric Filter	99	1.876	10,11,14,15
	Long Wet Kiln # 5	NO_X	388	None	LNB (indirect)	30-40	116 - 155	5,11,15,19
					LNB (direct)	40	155	5,11,15,19
					Biosolid Injection	23	89	5,11,15,19
					CemSTAR	20-60	78 - 233	5,11,15,19
					Mid-Kiln	20-50	78 - 194	5,11,15,19
					SCR	80	310	10,11,14,15
		SO_2	431	None	Wet FGD	90-99	388 - 427	10,11,14,15
		PM_{10}, $PM_{2.5}$, EC, OC	45	Dry ESP	Fabric Filter	82	37	2, 10,11,14,15

The GCC Dacotah Rapid City Plant cement kilns analyzed in this report are all long wet kilns. Kilns #4 and #5 have capacities of 550 tons of clinker per day each; assuming the kilns run 365 days of the year the result is 200,750 tons of clinker per year (tpy) per kiln. NO_X and SO_2 emissions from the Kiln #4 are 707 tpy and 27 tpy, respectively. NO_X and SO_2 emissions from the Kiln #5 are 388 tpy and 431 tpy, respectively. [1]

Combustion control options for NO_X include:

- Direct and indirect-fired low NO_X burners,
- The CemStar process, and
- Mid-kiln firing.

Kilns can be considered either direct- or indirect-fired kilns. Direct-fired kilns use more than 10% of primary air (i.e., air that is used for conveying the pulverized coal from the coal mill to the kiln). Indirect-fired kilns use less than 10% of primary air. Low NO_X burners can be used on either direct- or indirect-fired kilns. Low NO_X burners reduce flame turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion, thus reducing thermal NO_X formation.[5] The CemStar process adds a small amount of steel slag to the raw kiln feed and lower the temperature required to operate the kiln. Mid-kiln firing uses an additional feed injection mechanism and injects solid fuel into the calcining zone of a rotating kiln, thus lowering the temperature to produce clinker.

NO_X removal control options include:

- Biosolid injection,
- LoTOx™
- SCR,
- SNCR, and
- NO_XOUT

Biosolid injection uses biosolids from wastewater treatment plants to lower the kiln heating temperature required to produce clinker (biosolid tipping fees are such that often the annualized cost is negative, i.e., the plant receives a credit for using the technology). In the LoTOx™ system, ozone is injected into the kiln which oxidizes NO_X. The resulting higher oxides of nitrogen can then be removed by a wet scrubber.[6] LoTOx is licensed by the BOC group and is currently being used on the Midlothian cement wet kilns in Texas.[6,15] Both CemStar and biosolid injection are most feasible when there are nearby sources of steel slag or biowaste, respectively, that the cement plant can easily procure without incurring large transportation costs.

SCR uses an ammonia catalyst (such as a titanium dioxide or vanadium pentoxide mixture) to selectively reduce NO_X emissions from exhaust gases by converting NO_X to nitrate. The catalytic reactions can take place only in certain temperature ranges which are often higher than typical cement kiln flue gas temperatures. Process reconfigurations, such as an automatically activated bypass duct placed around the SCR reactor to control temperature fluctuations or installing equipment to maintain the desired temperature, can successfully deal with temperature issues.[6] Due to potential fouling problems of the catalyst the SCR system must be installed after the particulate collection device.

SNCR also reduces NO_X formation by ammonia or urea but does not use a catalyst. Instead the ammonia or urea is injected into the kiln. Similar to SCR, there is an ideal temperature range at which these reactions optimally occur. Long wet and dry kilns have the ideal temperature for SNCR reactions in the middle of the kiln, whereas preheater/precalciner kilns have the ideal temperature at the lower end of the preheater tower or at the cooler end of the kiln, i.e., not in the middle. Thus preheater/precalciner kilns are much more conducive to the SNCR technology and as such SNCR is not applicable to long wet and dry kills.

NO_XOUT is similar to the SNCR process and uses urea to complete the chemical conversion of NO to nitrate and oxygen. The temperature window is somewhat wider than typical SNCR systems due to an additive developed by the proprietors of the NO_XOUT technology.[5]

The clinker production process controls SO_2 to a significant degree.[7,8] The interior of the kiln is highly alkaline absorbs up to 95 percent of the SO_2 emissions generated, although this can vary depending on the kiln feed.[9] The option to control SO_2 is limited to flue gas desulfurization (FGD).[10] Flue gas is the primary source of SO_2 and volatile organic carbons (VOCs) – the fuel and raw materials dictate the amount of SO_2 emissions generated. Wet scrubbers have 80-99 percent control efficiency, although the generation of sludge and particulate build-up necessitates the FGD be installed downstream of a fabric filter.[11,1213] PM emissions are often controlled by fabric filters or wet or dry Electrostatic Precipitators (ESPs).[14,15] Kilns #4 and #5 at the GCC facility already have dry ESPs installed and thus only fabric filters are analyzed for further PM control.

4.1 Factor 1 – Costs

Table 4-2 provides cost estimates for the emission control options which have been identified for the South Dakota cement manufacturing plant. For each option, the table gives an estimate of the capital cost to install the necessary equipment (including any required instrumentation and equipment and all piping and ductwork), and the total annual cost of control, including the amortized cost associated with the capital equipment cost. The table also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

4.2 Factor 2 – Time Necessary for Compliance

Once the regional haze control strategy is formulated for South Dakota, up to 2 years will be needed for the state to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase

Table 4-2. Estimated Costs of Control for Selected Cement Manufacturing Operations in South Dakota

Company	Source	Control option	Pollutant	Estimated control efficiency (%)	Potential emission reduction (tons/year)	Estimated capital cost ($1000)	Estimated annual cost ($1000/year)	Cost effectiveness ($/ton)	Refer-ences
GCC Dacotah, Rapid City Plant	Long Wet Kiln # 4	LNB (indirect)	NO_X	30-40	212 - 283	526	129	3,092 - 1,859	5,14,15
		LNB (direct)	NO_X	40	283	1,873	331	7,788	5,14,15
		Biosolid Injection	NO_X	23	163	-	-	421.41	5,14,15
		CemSTAR	NO_X	20-60	14 - 424	1,599	299	4,476 - 13,459	5,14,15
		Mid-Kiln	NO_X	20-50	14 - 353	2,758	-315	6,922 - 17,328	5,14,15
		LoTOx™	NO_X	80-90	565 - 636	Unknown[a]		3155 - 3891	6,15
		SCR	NO_X	80	565	14,813	4,137	34	5,14,15
		Wet FGD	SO_2	90-99	24 - 26	9,133	1,370	403,942 - 437,604	10,11,15
		Fabric Filter	PM_{10}, EC, OC	99	134	1,357	1,148	18,699	10,11,15
		Fabric Filter	$PM_{2.5}$	99	67	1,235	1,045	37,399	10,11,15
	Long Wet Kiln # 5	LNB (indirect)	NO_X	30-40	116 - 155	526	129	4,229 - 5,651	5,14,15
		LNB (direct)	NO_X	40	155	1,873	331	14220	5,14,15
		Biosolid Injection	NO_X	23	89	-	-	0	5,14,15
		CemSTAR	NO_X	20-60	78 - 233	1,599	299	8,144 - 24,330	5,14,15
		LoTOx™	NO_X	80-90	310 - 349	Unknown[a]		3155 - 3891	6,15
		Mid-Kiln	NO_X	20-50	78 - 194	2,758	-315	12,594 - 31,324	5,14,15
		SCR	NO_X	80	310	14,813	4,137	61	5,14,15
		Wet FGD	SO_2	90-99	388 - 427	9,133	1,370	27,068	10,11,15
		Fabric Filter	PM_{10}, $PM_{2.5}$, EC, OC	82	37	1,235	1,045	110,421	2,10,11,15

a Cost effectiveness figures for LoTOx were not determined for dry kilns or preheater kilns, but only for wet kilns (the kilns that currently use the system) and precalciner kilns (developed from vendor information).

control equipment. The ICAC has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control.[16] However, state regulators' experience indicates that closer to 18 months is required to install this technology.[17] In the Clean Air Interstate Rule (CAIR) analysis, EPA estimated that approximately 30 months is required to design, build, and install SO_2 scrubbing technology for a single emission source.[18] The analysis also estimated that up to an additional 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility.

Based on these figures, the total time required to achieve emission reductions for the cement kilns would be up to 6½ years. This includes 2 years for regulatory development, 1 year for capital acquisition, and 2½ years for designing, building and installing a scrubber, if this option is selected. If catalyst additives are used, time will be required to select and test the appropriate additives, and to determine the optimum feed rate for the additive.

4.3 Factor 3 – Energy and Other Impacts

Table 4-3 shows the estimated energy and non-air pollution impacts of control measures for sources at the Wyoming cement manufacturing plant. The table shows the additional fuel, electricity, and steam requirements needed to operate the control equipment; and the additional solid waste that would be produced. CO_2 emissions associated with the generation of the additional electricity and steam are also estimated in the table.

A LoTOx™ scrubbing system or wet scrubbing system applied to the fluidized catalytic cracking unit would require electricity to operate fans and other auxiliary equipment, and would produce a wastewater stream which would require treatment. In addition, sludge from the scrubber would require disposal as solid waste. SCR and SNCR systems would also require electricity for fans, and SCR may require additional heat input as the temperature at which the catalytic reactions occur can be higher than the typical cement kiln flue gas temperatures, although it may be possible to use heat recovery systems to reheat and achieve the required temperature.[5] However, it is possible to use heat recovery systems to reheat the exhaust and avoid generating additional heat input. There is also the additional burden of getting rid of fouled or deactivated catalyst from the system – often the PM control device in the form of a fabric filter or electrostatic precipitator can achieve this goal.[5] SCR systems would produce additional solid waste because of spent catalyst disposal. Dust captured by an ESP or fabric filter would also require disposal as a solid waste. The presence of catalyst fines in the dust may require treatment as a hazardous waste.[19]

4.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of the cement kilns. However, industrial processes often refurbish cement kilns to extend their lifetimes. Therefore, the remaining lifetime of most equipment is expected to be longer than the projected lifetime of pollution control technologies which have been analyzed for these sources.

If the remaining life of an emission source is less than the projected lifetime of a pollution control device, then the capital cost of the control device would have to be amortized over a shorter period of time, corresponding to the remaining lifetime of the emission source. This would cause an increase in the amortized capital cost of the pollution control option, and a corresponding increase in the total annual cost of control. This increased cost can be quantified as follows:

$$A_1 = A_0 + C \times \frac{1 - (1 + r)^{-m}}{1 - (1 + r)^{-n}}$$

where:

A_1 = the annual cost of control for the shorter equipment lifetime ($)
A_0 = the original annual cost estimate ($)
C = the capital cost of installing the control equipment ($)
r = the interest rate (0.07)
m = the expected remaining life of the emission source (years)
n = the projected lifetime of the pollution control equipment

Table 4-3. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Selected Cement Manufacturing Operations in South Dakota

						Energy and non-air pollution impacts (per ton of emission reduced)				
Source Type		**Control Technology**	**Pollutant controlled**	**Potential emission reduction (tons/year)**	**Additional fuel requirement (%)**	**Electricity requirement (kW-hr)**	**Steam requirement (tons steam)**	**Solid waste produced (tons waste)**	**Wastewater produced (1000 gallons)**	**Additional CO_2 emitted (tons)**
GCC Dacotah, Rapid City Plant	Long Wet Kiln # 4	LNB (indirect)	NO_X	212 - 283	a	182				
		LNB (direct)	NO_X	283	a	182				
		Biosolid Injection	NO_X	163	a					
		NOXOUT	NO_X	247		b				
		CemSTAR	NO_X	14 - 424	a					
		Mid-Kiln	NO_X	14 - 353	a					
		LoTOx™	NO_X	565 - 636		c		b	b	c
		SCR	NO_X	565	9.8	57				b
		Wet FGD	SO_2	24 - 26	1,100	3	3	3.7		2.6
		Fabric Filter	PM_{10}, EC, OC	134		b		1		
		Fabric Filter	$PM_{2.5}$	67		b		1		
		Dry ESP	PM_{10}, EC, OC	44		b		1		
		Dry ESP	$PM_{2.5}$	21		b		1		
	Long Wet Kiln # 5	LNB (indirect)	NO_X	116 - 155	a					
		LNB (direct)	NO_X	155	a					
		Biosolid Injection	NO_X	89	a					
		NOXOUT	NO_X	136		b				
		CemSTAR	NO_X	78 - 233	a					
		Mid-Kiln	NO_X	78 - 194	a					
		LoTOx™	NO_X	310 - 349		c		b	b	c
		SCR	NO_X	310	9.8	57				b
		Wet FGD	SO_2	388 - 427	1,100	3	3	3.7		2.6
		Fabric Filter	PM_{10}, EC, OC	45		b		1		b
		Fabric Filter	$PM_{2.5}$	22		b		1		
		Dry ESP	PM_{10}, EC, OC	45.17	a	b		1		
		Dry ESP	$PM_{2.5}$	22.34214973	0.5	b		1		0.0

NOTES:

a - The measure is expected to improve fuel efficiency.

b - Some impact is expected but insufficient information is available to evaluate the impact.

c - According to the ERG Report (reference 5) "electricity and oxygen costs are reported to be high" although there is no quantification given.

blank indicates no impact is expected.

4.5 References for Section 4

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