Supplementary Information for Four Factor Analyses by WRAP States

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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

Contents

Abbreviations

ACT	Alternative Control Techniques
ALAPCO	Association of Local Air Pollution Control Officials
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAA	Clean Air Act
CO_2	Carbon Dioxide
EC	Elemental Carbon
EDMS	Emissions Data Management System
EGU	Electric Generating Units
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
FCC	Fluid Catalytic Cracking
FGR	Flue Gas Recirculation
FF	Fabric Filters
H_2S	Hydrogen Sulfide
ICAC	Institute of Clean Air Companies
ICI	Industrial/Commercial/Institutional
LEC	Low-Emission Combustion
LNB	Low-NOx Burners
MRPO	Midwest Regional Planning Organization
N_2O_5	Dinitrogen Pentoxide
NAAQS	National Ambient Air Quality Standards
NACAA	National Association of Clean Air Agencies
NEI	National Emissions Inventory
NESCAUM	Northeast States for Coordinated Air Use Management
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
NSCR	Nonselective Catalytic Reduction
NSPS	New Source Performance Standards
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
PSD	Prevention of Significant Deterioration
RPO	Regional Planning Organizations
SCC	Source Classification Codes
SCR	Selective Catalytic Reduction
SIC	Standard Industrial Classification
SNCR	Selective Noncatalytic Reduction
SO_2	Sulfur Dioxide

STAPPA	State and Territorial Air Pollution Program Administrators
ULNB	Ultra-Low NOx Burners
VOC	Volatile Organic Compounds
WRAP	Western Regional Air Partnership

Units

acfm	Actual Cubic Feet per Minute
cfm	Cubic Feet per Minute
kWh	Kilowatt Hour
MM-BTU/hr	Million British Thermal Units per Hour
MW	Megawatt
ppmv	Parts per Million by Volume
scfm	Standard Cubic Feet per Minute

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

The purpose of this report is to analyze these factors for possible control strategies intended to improve visibility in the WRAP region. The following priority source categories of emissions are addressed:

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
    a. Coal- and oil- fired
        i. By size category
            Up to and including 200 million British Thermal Units (BTU) per hour
            Greater than 200 million BTU/hour
        ii. By age category
            Constructed prior to regulations for Prevention of Significant Deterioration (PSD) (before August 7, 1977)
            After PSD regulations but before the Clean Air Act Amendments of 1990 (August 7, 1977 through December 31, 1990)
            After the Clean Air Act Amendments of 1990
    b. Wood fired industrial boilers
    c. Natural gas fired industrial boilers
5. Cement manufacturing plants
6. Sulfuric acid manufacturing plants
7. Pulp and paper plant lime kilns
8. Petroleum refineries

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 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 particulate organic carbon (OC). Data on emissions of volatile organic compounds (VOC) were also collected. In addition, although VOC emission control measures were not explicitly evaluated in this study, the impacts of NO_X, SO_2, and particulate matter controls on VOC were calculated where co-control benefits would occur.

It must be noted that the source category analyses in this report are general in nature. In developing their Regional Haze State Implementation Plans (SIPs), states will also draw on other category-specific analyses and source-specific analyses.

This report is organized in 10 sections, including this introduction. Section 2 describes the methodology for the four factor analysis. The next 8 sections present the results of factor analyses for the priority emission source categories listed above.

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* (June 1, 2007) indicates that the four-factor analyses should conform to the methodologies given in the *EPA Air Pollution Control Cost Manual*.[6] 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 (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. Reciprocating Internal Combustion Engines and Turbines

Reciprocating engines and turbines at industrial, commercial, and institutional facilities in the WRAP region are estimated to emit about 274,000 tons of NO_X per year, based on the 2002 emissions inventory for the region.[1] These sources are commonly grouped together under the general category of internal combustion engines. Most of the emissions from this category, about 247,000 tons per year, are from sources that are listed in the point source inventory; however, the area sources inventory also includes about 27,000 tons of NO_X emissions from internal combustion engines. The area source emissions estimates are derived from industrial, commercial, and institutional fuel consumption in the WRAP states. NO_X emissions from internal combustion engines represent about 23% of total point source emissions of NO_X in the WRAP region, and about 19% of all stationary source (point and area source) NO_X emissions in the region.

Table 3-1 shows estimated emissions of NO_X, SO_2, PM_{10}, $PM_{2.5}$ and VOC in the WRAP region, broken down by state, engine type, and fuel. The emissions estimates for NO_X, SO_2, and VOC were taken from the WRAP emissions data management system.[1] Estimates for PM_{10} and $PM_{2.5}$ were taken from the National Emissions Inventory (NEI). As the table shows, SO_2, VOC and particulate matter emissions from reciprocating engines and turbines sources are much lower than NO_X emissions. Emissions of OC and EC are not specifically quantified in either the WRAP inventory or the NEI, but can be estimated as a percentage of PM_{10} emissions using data from EPA's SPECIATE database.[2] EC and OC are estimated to comprise 78.8% and 18.5% of diesel PM_{10} emissions; and 38.4% and 24.7% of natural gas combustion PM_{10} emissions, respectively.

The point source emissions estimates in Table 3-1 include reciprocating engines and turbines used in oil and natural gas production and exploration operations, and at natural gas processing facilities. These emissions are included again in Chapters 3 and 4, which discuss control measures for these operations.

Reciprocating engines account for about 64% of the NO_X emissions from point sources in the internal combustion category, and turbines account for about 36%. The area source inventory does not differentiate between reciprocating engines and turbines, but reciprocating engines are expected to make up the bulk of area sources. Most of the turbines burn gaseous fuels, which include natural gas, liquefied petroleum gas, and industrial process gas. Reciprocating engines are divided between gaseous fuels and liquid fuels, such as kerosene and diesel oil.

Emissions from individual diesel reciprocating engines range up to 850 tons of NO_X per year, and natural gas fired reciprocating engine emissions range up to 1,370 tons of NO_X per year. Individual diesel-fired turbines range up to 1,400 tons of NO_X per year, and natural gas turbines range up to 877 tons NO_X per year.[1]

Table 3-1. Emissions from Reciprocating Internal Combustion Engines and Turbines in the WRAP Region

	AK	AZ	CA	CO	ID	MT	ND	NM	NV	OR	SD	UT	WA	WY	Tribes	Total
NO_X emissions in 2002 (tons/year)																
Point sources																
Turbines - gaseous fuel	44,293	3,593	11,832	4,233	697	321	524	9,433	4,088	2,028	372	1,302	1,267	2,113	1,890	87,987
Turbines - liquid	4,446	15	411	90	3	0	0	109	9	0	3	48	0	0	6	5,142
Reciprocating - gas	50	2,979	10,114	18,628	1,715	2,511	3,861	41,962	84	348	0	3,097	875	1,258	2,348	89,830
Reciprocating - liquid	12,779	1,370	12,735	5,336	312	3,968	305	6,714	209	0	7	2,156	114	13,060	5,051	64,116
Area source (unspecified)																
Natural gas	0	0	14,778	0	0	0	0	0	70	0	0	0	0	0	0	14,848
Kerosene	0	0	11,327	0	0	0	0	922	75	0	0	0	0	0	0	12,323
Total	61,569	7,957	61,197	28,287	2,726	6,800	4,691	59,141	4,535	2,376	383	6,602	2,256	16,431	9,294	274,246
SO_2 emissions in 2002 (tons/year)																
Point sources																
Turbines - gaseous fuel	705	31	352	143	7	9	20	20	20	31	11	22	85	4	18	1,479
Turbines - liquid	2,539	1	75	3	0	0	0	0	0	3	0	4	0	0	0	2,628
Reciprocating - gas	0	2	180	65	0	0	12	244	0	0	0	8	53	11	200	774
Reciprocating - liquid	670	37	689	71	23	234	8	53	14	0	0	185	553	1	19	2,557
Area source (unspecified)																
Natural gas	0	0	12	0	0	0	0	0	0	0	0	0	0	0	0	12
Kerosene	0	0	708	0	0	0	0	84	0	0	0	0	0	0	0	793
Total	3,915	71	2,016	281	31	243	40	402	34	35	11	219	691	17	238	8,243
PM_{10} emissions in 2002 (tons/year)																
Turbines - gas	167	765	459	335	976	115	0	105	27	542	4	6	13	0	2,481	5,995
Turbines - liquid	140	1	88	10	0	0	0	4	5	0	0	2	2	0	0	254
Reciprocating - gas	0	25	232	294	25	0	25	158	0	1	0	27	10	32	14	843
Reciprocating - liquid	179	14	436	42	201	56	2	64	135	1	0	26	1	0	279	1,435
Total	486	806	1,215	681	1,202	171	27	330	167	544	4	61	26	33	2,774	8,527
$PM_{2.5}$ emissions in 2002 (tons/year)																
Turbines - gas	66	665	450	242	966	36	0	53	25	129	3	5	11	0	1,743	4,394
Turbines - liquid	127	1	80	10	0	0	0	3	5	0	0	2	2	0	0	231
Reciprocating - gas	0	24	231	294	25	0	25	160	0	1	0	23	10	32	13	837
Reciprocating - liquid	168	13	418	34	69	38	2	63	131	1	0	22	1	0	127	1,089
Total	361	703	1,179	580	1,060	74	27	280	161	131	4	52	23	33	1,884	6,551
VOC emissions in 2002 (tons/year)																
Turbines - gas	665	93	1,088	652	27	66	40	548	20	217	35	81	65	49	69	3,715
Turbines - liquid	2	0	33	6	0	0	0	2	70	0	0	5	0	0	1	119
Reciprocating - gas	1	133	1,884	3,440	53	88	106	2,326	1	26	0	90	83	441	232	8,904
Reciprocating - liquid	466	29	824	1,340	11	216	23	3,044	9	0	0	198	7	1,236	128	7,531
Total	1,133	256	3,829	5,439	90	370	169	5,920	100	242	36	375	156	1,726	429	20,270

Source: NOX, SO2, and VOC emissions were taken from the WRAP emissions data management system, and PM10 and PM2.5 emissions were taken from the NEI.

Table 3-2 lists potential control measures for NO_X emissions from reciprocating engines and turbines. A number of options were identified for stationary reciprocating engines in an Alternative Control Techniques (ACT) guidance document written by the U.S. EPA in 1993, and in more recent analyses for New Source Performance Standards.[3,4] Reciprocating engines can be designed to operate under rich fuel mixture, or lean fuel mixture conditions. Air-to-fuel-ratio adjustments and ignition retarding adjustments can be used to control emissions under either fuel mixture condition and for diesel or natural gas engines. This approach typically requires the installation of an electronic control system. In addition, fuel efficiency is generally reduced and emissions of soot may be increased. Low-Emission Combustion (LEC) retrofit technology can also reduce emissions from lean burn reciprocating engines by an average of 89%.[5] LEC involves modifying the combustion system to achieve very lean combustion conditions (high air-to-fuel ratios). EPA prepared an update to the ACT guidance for reciprocating engines in 2002 which focused on LEC technology.[5] Selective Catalytic Reduction (SCR) can also be used either alone or in conjunction with the above technologies to reduce NO_X emissions from reciprocating engines or turbines by 90%.[6] In addition, Non-Selective Catalytic Reduction (NSCR) can be used for rich-burn natural gas engines.[4]

A separate ACT guidance document identifies control options for particulate matter emissions from diesel engines.[7] In addition, the WRAP sponsored a study of control options for engines used in the oil and gas industry.[8] This study covered control measures for NO_X, particulate matter, and VOC.

Another ACT guidance document analyzed control options for turbines using gaseous and liquid fuels.[9] Turbines can be retrofit with water or steam injection to reduce emissions by up to 80%. In addition, SCR can be used in conjunction with water or steam injection or low-NO_X burner technology to reduce emissions by 93 to 96%. The ACT did not analyze retrofit installations or low-NOX burner technology for turbines, or impact of SCR used alone (without water or steam injection or low-NO_X burner technology).

3.1 Factor 1 – Costs

Table 3-3 provides cost estimates for the emission control options which have been identified for reciprocating engines and turbines. 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. Retrofit costs were not available for low-NO_X burners.

The capital and annual cost figures are expressed in terms of the cost per unit of engine size, where the engine size is expressed in horsepower for reciprocating engines and million British thermal units per hour (MM-Btu/hr) for turbines. The table shows a range of values for each cost figure, since the cost per unit of engine size will depend on the engine size and other factors. The lower ends of the cost ranges typically reflect larger engines, and the higher ends of the cost ranges typically reflect lower engine sizes. Table 3-3 also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

Table 3-2. Control Options for Reciprocating Engines and Turbines

Source Type	Control Technology	Pollutant controlled	Baseline emissions (1000 tons/yr)	Estimated control effieiency (%)	Potential emission reduction (1000 tons/year)	Refer-ences
Turbines	Water or steam injection	NO_X	95	68 - 80	65 - 76	9
	Low-NO_X burners	NO_X	95	68 - 84	65 - 80	9
	SCR	NO_X	95	90	80	6,7,9
	Water or steam injection with SCR	NO_X	95	93 - 96	88 - 91	9
Reciprocating engines, gaseous fuels	Air-fuel ratio adjustment	NO_X	105	10 - 40	10 - 42	3
	Ignition retarding technologies	NO_X	105	15 - 30	16 - 31	3
	Low-emission combustion (LEC) retrofit	NO_X	105	80 - 90	84 - 94	5
	SCR	NO_X	105	90	94	3,4,6
	NSCR	NO_X	a	90 - 99	a	4
		VOC	a	40 - 85	a	4
	Replacement with electric motors	NO_X	105	100	105	8
		SO_2	0.79	100	0.79	
		PM_{10}	0.84	100	0.84	
		$PM_{2.5}$	0.84	100	0.84	
		EC	0.32	100	0.32	
		OC	0.21	100	0.21	
		VOC	8.9	100	8.9	
		Overall[b]	115		116	
Reciprocating engines, diesel and other liquid fuels	Ignition timing retard	NO_X	76	15 - 30	11 - 23	3,8
	EGR	NO_X	76	40	31	3,8
	SCR	NO_X	76	80 - 95	61 - 73	3,4,6,8
	Replacement of Tier 2 engines with Tier 4	NO_X	76	87	67	8
		PM_{10}	1.4	85	1.2	
		$PM_{2.5}$	1.1	85	0.9	
		EC	0.6	85	0.5	
		OC	0.5	85	0.4	
		VOC	7.5	87	6.6	
		Overall[b]	85		75	
	Diesel oxidation catalyst	PM_{10}	1.4	25	0.4	7,8
		$PM_{2.5}$	1.1	25	0.3	
		EC	0.6	25	0.2	
		OC	0.5	25	0.1	
		VOC	7.5	90	6.8	
		Overall[b]	9.0		7.2	

[a]NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not known.

[b]For control measures reducing multiple pollutants, overall emissions and emission reductions reflect the sum of all pollutants. However, EC, OC, and PM2.5 are components of PM10, and therefore are not added separately to the totals.

Table 3-3. Estimated Costs of Control Options for Reciprocating Engines and Turbines

Source Type	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Estimated capital cost ($/unit)	Estimated annual cost ($/year /unit)	Units	Cost effectiveness ($/ton)	Refer-ences
Turbines	Water or steam injection	NO_X	68 - 80	4.4 - 16	2 - 5	1000 Btu	560 - 3,100	9
	Low-NO_X burners[a]	NO_X	68 - 84	8 - 22	2.7 - 8.5	1000 Btu	5,200 - 16,200	9
	SCR	NO_X	90	8 - 22	2.7 - 8.5	1000 Btu	2000 - 10,000	6,7,9
	Water or steam injection with SCR	NO_X	93 - 96	13 - 34	5.1 - 13	1000 Btu	1,000 - 6,700	9
Reciprocating engines, gaseous fuels	Air-fuel ratio adjustment	NO_X	10 - 40	4.4 - 43	13 - 86	hp	320 - 8,300	3
	Ignition retarding technologies	NO_X	15 - 30	na	10 - 32	hp	310 - 2,000	3
	LEC retrofit	NO_X	80 - 90	120 - 820	30 - 210	hp	320 - 2,500	5
	SCR	NO_X	90	20 - 180	40 - 461	hp	430 - 4,900	3,4,6
	NSCR[b]	NO_X	90 - 99	17 - 35	3 - 6	hp	16 - 36	4
		VOC	40 - 85				1,500 - 6,200	4
		Overall[c]					16 - 36	
	Replacement with electric motors	NO_X	100	120 - 140	38 - 44	hp	100 - 4,700	8
		SO_2					>13,000	
		PM_{10}					>13,000	
		$PM_{2.5}$					>13,000	
		EC					>33,000	
		OC					>50,000	
		VOC					1,000 - 60,000	
		Overall[c]					90 - 4,300	
Reciprocating engines, diesel and other liquid fuels	Ignition timing retard	NO_X	15 - 30	16 - 120	14 - 66	hp	1,000 - 2,200	3,8
	EGR	NO_X	40	100	26 - 67	hp	780 - 2,000	3,8
	SCR	NO_X	80 - 95	100 - 2,000	40 - 1,200	hp	3,000 - 7,700	3,4,6,8
	Replacement of Tier 2 engines with Tier 4	NO_X	87	125	20	hp	900 - 2,400	8
		PM_{10}	85				25,000 - 68,000	
		$PM_{2.5}$	85				25,000 - 68,000	
		EC	85				>50,000	
		OC	85				>50,000	
		VOC	87				22,000 - 59,000	
		Overall[c]					840 - 2,200	
	Diesel oxidation catalyst	PM_{10}	25	10	1.7	hp	1,400	7,8
		$PM_{2.5}$	25				1,400	
		EC	25				3,300	
		OC	25				4,200	
		VOC	90				350	
		Overall[c]					280	

[a]Costs estimates for low-NO_X burners reflect the incremental costs of new low-NO_X burners versus standard burners. Retrofit costs for existing burners were not available.

[b]NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not known.

[c]For control measures reducing multiple pollutants, the overall cost-effectiveness is the cost per total reduction of all pollutants. However, EC, OC, and PM2.5 are components of PM10, and therefore are not added separately to the emission reduction total.

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 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control.[10] However, the time necessary will depend on the type and size of the unit being controlled. For instance, state regulators' experience indicates that closer to 18 months is required to install this technology.[11] Additional time up to 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 achieve emission reductions for reciprocating engines and turbines is estimated at a total of 5½ years.

3.3 Factor 3 – Energy and Other Impacts

Table 3-4 shows the estimated energy and non-air pollution impacts of control measures for reciprocating engines and turbines. In general, air-to-fuel-ratio adjustments and ignition retarding technologies have been found to increase fuel consumption by up to 5%, with a typical value of about 2.5%.[12,13] This increased fuel consumption would result in increased CO_2 emissions. LEC technology is not expected to increase fuel consumption; and may provide some fuel economy.[12]

Diesel oxidation catalyst and diesel filtration technologies would produce an increase in fuel consumption in order to overcome the pressure drop through the catalyst bed and the filter. This is assumed to be roughly the same as the increase in fuel consumption for SCR installations, about 0.5%.[12] In the case of diesel oxidation catalyst, the catalyst would have to be changed periodically, producing an increase in solid waste disposal.[14] If diesel reciprocating engines are replaced with electric motors, there would be an increase in electricity demand, but this would be offset by the fuel consumption that would be avoided by replacing the engine.

For turbines, water injection and steam injection would require electricity to operate pumps and ancillary equipment.[14] Water injection would produce an increase in fuel consumption in order to evaporate the water, and steam injection would require energy to produce the steam. The increased electricity, steam, and fuel demands would produce additional CO_2 emissions.

Installation of SCR on any type of engine would cause a small increase in fuel consumption, about 0.5%, in order to force the exhaust gas through the catalyst bed.[12] This would 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.[14]

Table 3-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Reciprocating Engines and Turbines

Source Type	Control Technology	Pollutant controlled	Potential emission reduction (1000 tons/year)	Additional fuel requirement (%)	Energy and non-air pollution impacts (per ton of emission reduced)				
					Electricity requirement (kW-hr)	Steam requirement (tons steam)	Solid waste produced (tons waste)	Wastewater produced (1000 gallons)	Additional CO_2 emitted (tons)
Turbines	Water or steam injection	NO_X	65 - 76	a		31			8.1
	Low-NO_X burners	NO_X	65 - 80	a					
	SCR	NO_X	80	a					
	Water or steam injection with SCR	NO_X	88 - 91	0.45			0.026		1.7
Reciprocating engines, gaseous fuels	Air-fuel ratio controllers	NO_X	10 - 42	a					
	Ignition retarding technologies	NO_X	16 - 31	a					
	LEC retrofit	NO_X	84 - 94	a					
	SCR	NO_X	94	0.5			0.008		0.43
	NSCR	NO_X, VOC	d	0.5			0.008		0.24
	Replacement with electric motors	NO_X	105	(100)	66,000				b
		SO_2	0.79						
		PM_{10}	0.84						
		$PM_{2.5}$	0.84						
		EC	0.32						
		OC	0.21						
		VOC	8.9						
		Overall[e]	116						
Reciprocating engines, diesel and other liquid fuels	Ignition timing retard	NO_X	11 - 23	a					
	EGR	NO_X	31	2.7					2.0
	SCR	NO_X	61 - 73	0.5			0.008		0.38
	Replacement of Tier 2 engines with Tier 4	NO_X	67	c					c
		PM_{10}	1.2						
		$PM_{2.5}$	0.9						
		EC	0.5						
		OC	0.4						
		VOC	6.6						
		Overall[e]	75						
	Diesel oxidation catalyst	PM_{10}	0.4	0.5			b		316
		$PM_{2.5}$	0.3						
		EC	0.2						
		OC	0.1						
		VOC	6.8						2.5
		Overall[e]	7.2						2.6[d]

NOTES:

blank indicates no impact is expected.

[a]The measure is expected to improve fuel efficiency.

[b]CO_2 from the generation of electricity would be offset by avoided emissions due to replacing the diesel engine

[c]EPA has estimated that the control measures used to meet Tier 4 standards will be integrated into the engine design so that sacrifices in fuel economy will be negligible.

[d]NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not known.

[e]For control measures reducing multiple pollutants, overall emissions and reflect the sum of all pollutants. However, EC, OC, and $PM_{2.5}$ are components of PM_{10}, and therefore are not added separately to the totals. Impacts are expressed as the impact per ton of total polluants reduced.

3.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of reciprocating engines and turbines in the WRAP region. However, engines in industrial service are often refurbished to extend their lifetimes. Therefore, the remaining lifetime of most reciprocating engines and turbines is expected to be longer than the projected lifetime of pollution control technologies which have been analyzed for this category. In the case of add-on technologies such as SCR, the projected lifetime is 15 years.

If the remaining life of a reciprocating engine or turbine 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

3.5 References for Section 3

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4. Oil and Gas Exploration and Production Field Operations

The WRAP region is an important domestic source of crude oil and natural gas. Many of the WRAP states have active production fields for oil and natural gas; and exploration operations are also underway to identify additional reserves. Both the production and exploration industries involve a number of operations which emit NO_X, SO_2, particulate matter and VOC. Turbines are used to drive compressors and other equipment, and diesel engines are used in a variety of applications. Flares and incinerators are used to dispose of waste gases, and process heaters are used in various operations. In addition, emissions emanate from various gas treatment operations, such as glycol dehydrators and amine treatment units.

Table 4-1 summarizes emissions from the industry, broken down by state and by the various emission sources. Point source emissions of NO_X, SO_2, and VOC from these operations were extracted from the 2002 WRAP emissions inventory, which catalogs emission sources by their Standard Industrial Classification (SIC).[1] SIC 131 covers crude petroleum and natural gas production, and SIC 138 covers oil and gas field exploration services. Estimates for PM_{10} and $PM_{2.5}$ were extracted from the 2002 National Emissions Inventory (NEI), which also classifies emissions by SIC. It must be noted that the point source emissions in Table 4-1 for reciprocating engines and turbines in the oil and gas production and exploration sector are also included in the emission totals reported in Table 3-1 (for all reciprocating engines and turbines). However, the point source inventories do not include small engines such as oil well motors and gas well engines. Emissions for these sources have been estimated by the WRAP in a separate oil and gas industry study,[2] and these estimates are also included in Table 4-1.

Based on the inventory emissions estimates, NO_X emissions are the predominant regional haze precursor emissions in oil and gas exploration and production operations. Overall NO_X emissions from these operations are estimated at about 294,000 tons/year, which represent about 20% of stationary source (point and area source) NO_X emissions in the region. These result from combustion processes in engines, turbines, heaters, incinerators, and flares. It should be noted that emissions from point source engines and turbines, about 166,000 tons/year, also fall into the reciprocating engines and turbines category discussed in Chapter 3. However, according to an analysis of oil and gas emission sources sponsored by the WRAP, emissions estimates from small engines at oil and gas operations are not believed to be included in the area source inventory internal combustion estimates.[2]

Most turbines at oil and gas production and exploration operations are fired by natural gas. Emissions from individual natural gas turbines at production operations range up to about 877 tons of NO_X per year, which is comparable to natural gas turbines at industrial facilities. Emissions from individual natural gas turbines at exploration operations range up to 131 tons of NO_X per year. Natural gas reciprocating engines at oil and gas production and exploration operations are somewhat smaller than natural gas reciprocating engines at industrial facilities. NO_X emissions from individual gas reciprocating engines range up to 700 tons per year for oil

Table 4-1. Emissions from Oil and Gas Production and Exploration in the WRAP Region

Emission source			AK	AZ	CA	CO	ID	MT	ND	NM	NV	OR	SD	UT	WY	Tribes	Total
						NO_X emissions (tons/year)											
Production	Point sources	Recip. Engines (mostly gas)	4,208	642	8,050	24,525	2,590	3,996	4,838	52,219	83	1,182	323	2,983	12,272	1,127	119,519
		Turbines, gas	40,987		2,490	571		0	0	345	0			66	956	630	46,044
		Process heaters	935		1,518	100		4	84	339	0			12	92	1	3,085
		Flares	361		72	17		0	164	48	0			12	95	2	772
	Other engines	Oil well motors	0	0		9		42	75	329	1		3	31	111		601
		Compressor engines		8		3,271		1,791	2,920	35,140	33	73	284	843	1,791		46,154
		Other gas well engines	9	9	8,070	15,946		4,678	101	14,602	4	12	44	2,127	6,398		52,000
		Coal methane pumps				1,489				92					1,428		3,009
Exploration	Point sources	Recip. Engines (mostly gas)	235		268	123		0	0	3,447	0			0	195	0	4,269
		Turbines, gas	0		0	0		0	0	890	0			0	0	0	890
		Other	64		128	93		0	0	187	0			18	182	2	673
	Non-point engines	Drill rig motors	877			2,803		1,046	1,536	5,476	24		29	334	4,997		17,122
Total			47,677	659	20,597	48,947	2,590	11,557	9,718	113,113	145	1,267	683	6,426	28,517	1,762	293,658
						SO_2 emissions (tons/year)											
Production	Point sources	Incinerators	0		17	0		0	199	0	0			1,420	7,404	0	9,041
		Flares	38		158	3		2	77	3,822	0			33	4,318	48	8,499
		Sulfur recovery units	0		0	0		0	283	820	0			0	1,284	0	2,387
		Process heaters (gas)	92		730	1		0	0	69	0			0	0	3	896
		Turbines, gas	704		57	1		0	0	0	0			1	0	10	773
		Recip. Engines (mostly gas)	17		43	35		0	11	0	0			0	0	196	302
		Other	8		95	55		0	0	36	0			0	2	1	197
Exploration	Non-point engines	Drill rig motors	66			118		225	358	244	1		6	17	150		1,185
Total			926		1,099	212		227	929	4,992	1		6	1,472	13,159	258	23,280
						PM_{10} emissions (tons/year)											
Production	Point sources	Process heaters, gas	50	0	268	7	0	0	0	12	0	0	0	0	2	0	339
		Recip. Engines (mostly gas)	0		11	189		0	0	3	0			3	5	0	211
		Turbines, gas	144		36	13		0	0	1	0			0	0	0	194
		Other	107	0	70	14	0	0	0	14	0	0	0	3	1	0	209

Table 4-1. Emissions from Oil and Gas Production and Exploration in the WRAP Region

Emission source			AK	AZ	CA	CO	ID	MT	ND	NM	NV	OR	SD	UT	WY	Tribes	Total
Exploration	Point sources	General	0	0	10	2	0	0	0	7	0	0	0	0	0	0	19
Total			301	0	395	224	0	0	0	37	0	0	0	6	8	0	972
PM $_{2.5}$ emissions (tons/year)																	
Production	Point sources	Process heaters, gas	44		268	7		0	0	12	0			0	2	0	333
		Recip. Engines (mostly gas)	0		11	189		0	0	3	0			1	5	0	209
		Turbines - natural gas	60		34	12		0	0	1	0			0	0	0	108
		Other	65	0	69	13	0	0	0	12	0	0	0	2	1	0	162
Exploration	Point sources	General	0	0	10	1	0	0	0	7	0	0	0	0	0	0	18
Total			169	0	392	222	0	0	0	35	0	0	0	4	8	0	830
VOC emissions (tons/year)																	
Production	Point sources	Recip. Engines (mostly gas)	209		647	3,697		28	55	670	0			96	294	213	5,908
		Fugitive emissions	0		1,302	1,079		6	0	125	3			75	747	50	3,388
		Glycol dehydrator	25		3	2,669		2	0	126	0			48	229	95	3,195
		Other	2		602	1,313		0	0	1	17			61	297	48	2,340
		Storage	0		405	611		2	0	125	3			41	43	20	1,251
		Process heaters	49		167	751		0	6	159	0			1	11	20	1,163
		Turbines	641		210	103		0	0	11	0			14	42	46	1,066
		Flares	527		67	10		0	6	33	0			25	33	3	704
Exploration	Point sources	Recip. Engines (mostly gas)	5		6	34		0	0	1,900	0			0	107	0	2,052
		Storage	0		1	0		0	0	979	0			0	1	0	981
		Glycol dehydrator	0		0	34		0	0	605	0			0	6	0	645
		Fugitive emissions	0		0	2		0	0	180	0			0	30	0	213
		Other	11		15	113		0	0	233	0			1	252	1	626
Total			1,469		3,424	10,417		38	67	5,148	22			361	2,090	497	23,533

and gas production operations, and up to 210 tons per year for exploration operations, compared with a maximum of 1,370 tons per year for reciprocating engines at industrial facilities. Diesel engines at oil and gas operations are also smaller than those at industrial facilities. NO_X emissions from individual diesels range up to 46 tons per year for production operations, and 10 tons per year for exploration operations, compared with 850 tons per year for the largest industrial diesel engine.[1]

SO_2 emissions from oil and gas exploration and production are estimated to be an order of magnitude lower than NO_X emissions. SO_2 emissions from incinerators and flares result from the presence of sulfur compounds in waste gases that are burned at the production site. These are generally the waste gases from natural gas sweetening operations such as amine treatment units. Although the process heaters at oil and gas production facilities are listed as using natural gas fuel, SO_2 emissions from these sources are reported to be about 4,000 tons/year. These emissions may result from the combustion of unsweetened natural gas at the well head. SO_2 emissions from drill rig motors also result from the presence of sulfur compounds in the motor fuels.

PM_{10}, $PM_{2.5}$, and VOC emissions from oil and gas exploration and production are also estimated to be an order of magnitude lower than NO_X emissions. Emissions of OC and EC are specifically quantified in either the WRAP inventory or the NEI, but can be estimated as a percentage of PM_{10} emissions using data from EPA's SPECIATE database.[3] EC and OC are estimated to comprise 78.8% and 18.5% of diesel PM_{10} emissions; and 38.4% and 24.7% of natural gas combustion PM_{10} emissions, respectively.

Table 4-2 lists potential control measures for oil and gas production and exploration emissions. The table includes options for reciprocating engines and turbines, process heaters, flares and incinerators, and sulfur recovery units. As discussed in Chapter 3, a number of options are available to control emissions from gas-fired reciprocating engines, diesel-fueled reciprocating engines, and turbines.[2,4,5,6,7,8] Reciprocating engines can be designed to operate under rich fuel mixture, or lean fuel mixture conditions. Air-to-fuel-ratio adjustments and ignition retarding technologies can be used to control emissions under either fuel mixture condition. Low-Emission Combustion (LEC) retrofit technology which can also reduce emissions from lean burn reciprocating engines by an average of 89%. LEC involves modifying the combustion system to achieve very lean combustion conditions (high air-to-fuel ratios). Selective Catalytic Reduction (SCR) can also be used either alone or in conjunction with the above technologies to reduce NO_X emissions from reciprocating engines or turbines by 90%. In addition, Non-Selective Catalytic Reduction (NSCR) can be used for rich-burn natural gas engines.[8]

SO_2 emissions from incinerators and flares could be avoided by installing sulfur recovery units to remove sulfur from the waste gases prior to incineration or flaring.[9] These emissions can also be reduced by compressing sulfur-containing acid gases and injecting these gases into non-producing rock formations.[10] Flue gas scrubbing has also been used to control SO_2 emissions from incinerators.[11,12] SO_2 emissions from existing sulfur recovery units can be reduced by adding additional recovery stages, or by adding a tail gas treatment unit.[12] In some cases, it may be possible to avoid SO_2 emissions from process heaters by substituting a lower-sulfur sweetened natural gas for the gas currently being burned. A number of options are available to

Table 4-2. Control Options for Oil and Gas Production and Exploration

Source Type	Control Technology	Pollutant controlled	Baseline emissions (1000 tons/yr)	Estimated control efficiency (%)	Potential emission reduction (1000 tons/year)	Refer-ences
Compressor engines and gas fueled reciprocating engines	Air-fuel ratio adjustment	NO_X	166	10 - 40	17 - 66	2,5
	Ignition timing retard	NO_X	166	15 - 30	25 - 50	2
	Low-emission combustion (LEC) retrofit	NO_X	166	80 - 90	130 - 150	2,5
	SCR	NO_X	166	90	150	2,8,12
	NSCR	NO_X	a	90 - 99	a	8
		VOC	a	40 - 85	a	8
	Replacement with electric motors	NO_X	166	100	166	2
		SO_2	0.30	100	0.30	
		PM_{10}	0.21	100	0.21	
		$PM_{2.5}$	0.21	100	0.21	
		EC	0.08	100	0.08	
		OC	0.05	100	0.05	
		VOC	5.9	100	5.9	
		Overall[b]	172		172	
Drilling rig engines and other diesel engines	Ignition timing retard	NO_X	60	15 - 30	9 - 18	2
	Exhaust gas recirculation	NO_X	60	40	24	2
	SCR	NO_X	60	80 - 95	48 - 57	2,8,12
	Replacement of Tier 2 engines with Tier 4	NO_X	60	87	52	2
		PM_{10}	0.2	85	0.2	2
		$PM_{2.5}$	0.2	85	0.2	
		EC	0.1	85	0.1	
		OC	0.1	85	0.1	
		VOC	8.0	87	6.9	2
		Overall[b]	68		59	
	Diesel oxidation catalyst	PM_{10}	0.23	25	0.06	2
		$PM_{2.5}$	0.18	25	0.05	
		EC	0.10	25	0.03	
		OC	0.08	25	0.02	
		VOC	8.0	90	7.2	2
		Overall[b]	8.2		7.3	
Turbines	Water or steam injection	NO_X	47	68 - 80	32 - 38	11
	Low-NO_X burner (LNB)	NO_X	47	68 - 84	32 - 39	11
	SCR	NO_X	47	90	42	6,7,12
	Water or steam injection with SCR	NO_X	47	93 - 96	44 - 45	11

Table 4-2. Control Options for Oil and Gas Production and Exploration

Source Type	Control Technology	Pollutant controlled	Baseline emissions (1000 tons/yr)	Estimated control efficiency (%)	Potential emission reduction (1000 tons/year)	Refer-ences
Flares	Add or expand sulfur recovery unit	SO_2	8.5	90 - 95	c	9
	Acid gas injection	SO_2	8.5	100	c	10
Incinerators	Spray dryer absorber	SO_2	9.0	80 - 95	7.2 - 8.6	12
	Wet FGD	SO_2	9.0	90 - 99	8.1 - 9	11,12
	Acid gas injection	SO_2	9.0	100	c	10
Sulfur recovery units	Additional recovery stages	SO_2	2.4	94 - 96	2.2 - 2.3	11,14
	Tail gas treatment unit (TGTU)	SO_2	2.4	90 - 99.5	2.1 - 2.4	11,14
Process heaters	Substitution of lower sulfur fuel	SO_2	4.0	up to 90	0 - 3.6	9,12
	LNB	NO_X	3.1	40	1.2	13,14
	ULNB	NO_X	3.1	75 - 85	2.3 - 2.6	12,13,14
	LNB and FGR	NO_X	3.1	48	1.5	13,14
	SNCR	NO_X	3.1	60	1.9	12,13,14
	SCR[d]	NO_X	3.1	70 - 90	2.2 - 2.8	12,13,14
	LNB and SCR	NO_X	3.1	70 - 90	2.2 - 2.8	12,13,14
Glycol dehydrators	Optimize glycol circulation rate	VOC	3.8	33 - 67	1.3 - 2.6	2

[a]NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not known.

[b]For control measures reducing multiple pollutants, overall emissions and emission reductions reflect the sum of all pollutants. However, EC, OC, and PM2.5 are components of PM10, and therefore are not added separately to the totals.

[c]Insufficient information is available in the emissions inventory to determine the percentage of flare or incinerator emissions in this category that is amenable to these control strategies.

[d]SCR can be used for mechanical draft process heaters. Natural draft heaters would have to be converted to mechanical draft for installation of SCR.

reduce NO_X emissions from process heaters. Combustion modifications including low-NO_X burners (LNB), ultralow-NO_X burners (ULNB), and flue gas recirculation (FGR) reduce the formation of NO_X. In addition, flue gases from the process heaters can be treated with selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) to reduce NO_X emissions. These post-combustion controls can be used either alone or in conjunction with combustion controls.[13,14]

4.1 Factor 1 – Costs

Table 4-3 provides cost estimates for the emission control options which have been identified for oil and gas production and exploration operations. 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 and annual cost figures are expressed in terms of the cost per unit of engine size or per unit of process throughput. Engine size is expressed in horsepower for reciprocating engines and MMBtu/hour for turbines. Throughput for process heaters is also expressed in MMBtu/hour. Process throughput for sulfur recovery units is expressed in terms of the amount of sulfur recovered.

Sulfur recovery units are believed to be more cost-effective than post-combustion controls for reducing SO_2 emissions from flares and incinerators at oil and gas production operations. Recent analyses of controls for Regional Haze precursors have focused on add-on controls for SO_2, rather than such process modifications. However, costs of sulfur recovery units were estimated in an earlier study of model refineries in different size ranges.[9] These estimates have been updated to current dollars using the Chemical Engineering plant cost index.

Table 4-3 shows a range of values for each cost figure, since the cost per unit of process throughput size will depend on the process size and other factors. The lower ends of the cost ranges typically reflect larger engines or processes, and the higher ends of the cost ranges typically reflect smaller engines or processes. 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 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 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control.[15] However, the time necessary will depend on the type and size of the unit being controlled. For instance, state regulators' experience indicates that closer to 18 months is required to install this technology.[16] In the CAIR analysis, EPA estimated that approximately 30 months is required to design, build, and install SO_2 scrubbing technology for a single emission source.[17] 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 oil and gas production and exploration operations is estimated at a total of 6½ years.

Table 4-3. Estimated Costs of Control for Oil and Gas Production and Exploration

Source Type	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Estimated capital cost ($/unit)	Estimated annual cost ($/year /unit)	Units	Cost effectiveness ($/ton)	References
Compressor engines	Air-fuel ratio adjustment	NO_X	10 - 40	5.3 - 42	0.9 - 6.8	hp	68 - 2,500	2,5
	Ignition timing retard	NO_X	15 - 30	na	1 - 3	hp	42 - 1,200	2
	LEC retrofit	NO_X	80 - 90	120 - 820	30 - 210	hp	320 - 2,500	5
	SCR	NO_X	90	100 - 450	40 - 270	hp	870 - 31,000	2,8,12
	NSCR[a]	NO_X	90 - 99	17 - 35	3 - 6	hp	16 - 36	8
		VOC	40 - 85				1,500 - 6,200	8
		Overall[b]					16 - 36	
	Replacement with electric motors	NO_X	100	120 - 140	38 - 44	hp	100 - 4,700	2
		SO_2					>55,000	
		PM_{10}					>79,000	
		$PM_{2.5}$					>79,000	
		EC					>205,000	
		OC					>319,000	
		VOC					3,000 - 130,000	
		Overall[b]					100 - 4,500	
Drilling rig engines and other engines	Ignition timing retard	NO_X	15 - 30	16 - 120	14 - 66	hp	1,000 - 2,200	2
	EGR	NO_X	40	100	26 - 67	hp	780 - 2,000	2
	SCR	NO_X	80 - 95	100 - 2,000	40 - 1,200	hp	3,000 - 7,700	2,8,12
	Replacement of Tier 2 engines with Tier 4	NO_X	87	125	20	hp	900 - 2,400	2
		PM_{10}	85	125	20	hp	25,000 - 68,000	2
		$PM_{2.5}$						
		EC						
		OC						
		VOC	87	125	20	hp	22,000 - 59,000	2
		Overall[b]					840 - 2,200	
	Diesel oxidation catalyst	PM_{10}	25	10	1.7	hp	1400	2
		$PM_{2.5}$					1400	
		EC					3,300	
		OC					4,200	
		VOC	90	10	1.7	hp	350	2
		Overall[b]					280	

Table 4-3. Estimated Costs of Control for Oil and Gas Production and Exploration

Source Type	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Estimated capital cost ($/unit)	Estimated annual cost ($/year /unit)	Units	Cost effectiveness ($/ton)	Refer-ences
Turbines	Water or steam injection	NO_X	68 - 80	4.4 - 16	2 - 5	1000 BTU	560 - 3,100	7
	Low-NO_X burners[c]	NO_X	68 - 84	8 - 22	2.7 - 8.5	1000 BTU	2,000 - 10,000	7
	SCR	NO_X	90	13 - 34	5.1 - 13	1000 BTU	1,000 - 6,700	6,7,12
	Water or steam injection with SCR	NO_X	93 - 96	13 - 34	5.1 - 13	1000 BTU	1,000 - 6,700	7
Flares	Add or expand sulfur recovery unit	SO_2	90 - 95	0.1 - 1.1	28 - 190	ton-Sulfur/year	14 - 95	9
	Acid gas injection	SO_2	100					10
Incinerators	Spray dryer absorber	SO_2	80 - 95				1,500-1,900	12
	Wet FGD	SO_2	90 - 99				1,500 - 1,800	11,12
	Acid gas injection	SO_2	100					10
Sulfur recovery units	Additional recovery stages	SO_2	94 - 96					11,14
	Tail gas treatment unit (TGTU)	SO_2	90 - 99.5				1,100 - 1,200	11,14
Process heaters	Substitution of lower sulfur fuel	SO_2	up to 90					9,12
	LNB	NO_X	40	3.8 - 7.6	0.41 - 0.81	1000 BTU	2,100 - 2,800	13,14
	ULNB	NO_X	75 - 85	4.0 - 13	0.43 - 1.3	1000 BTU	1,500 - 2,000	12,13,14
	LNB and FGR	NO_X	48	16	1.7	1000 BTU	2,600	13,14
	SNCR	NO_X	60	10 - 22	1.1 - 2.4	1000 BTU	4,700 - 5,200	12,13,14
	SCR[d]	NO_X	70 - 90	33 - 48	3.7 - 5.6	1000 BTU	2,900 - 6,700	12,13,14
	LNB and SCR	NO_X	70 - 90	37 - 55	4 - 6.3	1000 BTU	2,900 - 6,300	12,13,14
Glycol dehydrators	Optimize glycol circulation rate	VOC	33 - 67	31 - 170	5 - 28	gal/hr		2

[a]NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not known.

[b]For control measures reducing multiple pollutants, the overall cost-effectiveness is the cost per total reduction of all pollutants. However, EC, OC, and PM2.5 are components of PM10, and therefore are not added separately to the emission reduction total.

[c]Costs estimates for low-NO_X burners for turbines reflect the incremental costs of new low-NO_X burners versus standard burners. Retrofit costs for existing burners were not available.

[d]SCR cost estimates for process heaters apply to mechanical draft heaters. Natural draft heaters would have to be converted to mechanical draft for installation of SCR. This would increase both the capital and annualized costs of control by about 10%.

4.3 Factor 3 – Energy and Other Impacts

Table 4-4 shows the estimated energy and non-air pollution impacts of control measures for sources at oil and gas production and exploration operations. For gas-fired reciprocating engines and diesel engines, air-to-fuel-ratio adjustments and ignition retarding technologies have been found to increase fuel consumption by up to 5%, with a typical value of about 2.5%.[18,19] This increased fuel consumption would result in increased CO_2 emissions. LEC technology is not expected to increase fuel consumption; and may provide some fuel economy.[18]

Diesel oxidation catalyst and diesel filtration technologies would produce an increase in fuel consumption in order to overcome the pressure drop through the catalyst bed and the filter. In the case of diesel oxidation catalyst, the catalyst would have to be changed periodically, producing an increase in solid waste disposal.[20] If diesel reciprocating engines are replaced with electric motors, there would be an increase in electricity demand, but this would be offset by the fuel consumption that would be avoided by replacing the engine.

For turbines, water injection and steam injection would require electricity to operate pumps and ancillary equipment.[20] Water injection would produce an increase in fuel consumption in order to evaporate the water, and steam injection would require energy to produce the steam. The increased electricity, steam, and fuel demands would produce additional CO_2 emissions.

Installation of SCR on any type of engine would cause a small increase in fuel consumption, about 0.5%, in order to force the exhaust gas through the catalyst bed.[18] This would 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.[20]

Sulfur recovery units require electricity and steam. Wet or dry scrubbers applied to incinerators and tail gas treatment units applied to sulfur recovery units would use electricity for the fan power needed to overcome the scrubber pressure drop. These systems would also produce solid waste, and wet scrubbers would produce wastewater which would require treatment. Injection of acid gases would require the consumption of fuel to compress the gases. However, this option would also result in the sequestration of CO2 present in the injected gas stream.[10]

Low-NO_X burners for process heaters are expected to improve overall fuel efficiency. FGR would require additional electricity to recirculate the fuel gas into the heater. In SCR systems for process heaters, fans would be required to overcome the pressure drop through the catalyst bed. The fans would require electricity, with resultant increases in CO_2 to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal.[20]

Table 4-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Oil and Gas Production and Exploration

Source Type	Control Technology	Pollutant controlled	Potential emission reduction (1000 tons/year)	Additional fuel requirement (%)	Energy and non-air pollution impacts (per ton of emission reduced): Electricity requirement (kW-hr)	Steam requirement (tons steam)	Solid waste produced (tons waste)	Wastewater produced (1000 gallons)	Additional CO_2 emitted (tons)
Compressor engines	Air-fuel ratio adjustment	NO_X	17 - 66	a					
	Ignition retarding technologies	NO_X	25 - 50	a					
	LEC retrofit	NO_X	130 - 150	a					
	SCR	NO_X	150	0.5			0.008		0.43
	NSCR	NO_X, VOC	e	0.5			0.008		0.24
	Replacement with electric motors	NO_X	166	(100)	66,000				b
Drilling rig engines and other engines	Ignition timing retard	NO_X	9 - 18	a					
	EGR	NO_X	24	2.7					2.0
	SCR	NO_X	48 - 57	0.5			0.008		0.38
	Replacement of Tier 2 engines with Tier 4	NO_X	52	c					c
		$PM_{2.5}$, PM_{10}, EC, OC	0.2	c					c
		VOC	6.9	c					c
		Total[e]	59						
	Diesel oxidation catalyst	$PM_{2.5}$, PM_{10}, EC, OC	0.1	0.5			b		316
		VOC	7.2						2.5
		Total[f]	7.3						2.6[e]
Turbines	Water or steam injection	NO_X	32 - 38	a		31			8.1
	Low-NO_X burner (LNB)	NO_X	32 - 39	a					
	SCR		42	a					
	Water or steam injection with SCR	NO_X	44 - 45	0.45			0.026		1.7

Table 4-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Oil and Gas Production and Exploration

Source Type	Control Technology	Pollutant controlled	Potential emission reduction (1000 tons/year)	Additional fuel requirement (%)	Energy and non-air pollution impacts (per ton of emission reduced): Electricity requirement (kW-hr)	Steam requirement (tons steam)	Solid waste produced (tons waste)	Wastewater produced (1000 gallons)	Additional CO_2 emitted (tons)
Process heaters	Substitution of lower sulfur fuel	SO_2	0 - 3.6	b					b
	LNB	NO_X	1.2	a	g				
	ULNB	NO_X	2.3 - 2.6	a	g				
	LNB and FGR	NO_X	1.5		3,300				3.3
	SNCR	NO_X	1.9	0.16	460				3.2
	SCR	NO_X	2.2 - 2.8		8,400		0.073		8.4
	LNB and SCR	NO_X	2.2 - 2.8		8,400		0.073		8.4
Flares	Add or expand sulfur recovery unit	NO_X	up to 8.5		270	3.2	<0.01		1.1
	Acid gas injection	SO_2	up to 8.5	d					h
Incinerators	Spray dryer absorber	SO_2	7.2 - 8.6		400		3.7		1.1
	Wet FGD	SO_2	8.1 - 9		1,100	3.1	2.8	3.7	2.6
	Acid gas injection	SO_2	up to 9.0	d					h
Sulfur recovery units	Additional recovery stages	SO_2	2.2 - 2.3		270	3.2	<0.01		1.1
	Tail gas treatment unit (TGTU)	SO_2	2.1 - 2.4		190	3.5		3.7	1.1
Glycol dehydrators	Optimize glycol circulation rate	VOC	1.3 - 2.6	a					

NOTES:

blank indicates no impact is expected.

[a]The measure is expected to improve fuel efficiency.

[b]CO_2 from the generation of electricity would be offset by avoided emissions due to replacing the diesel engine

[c]EPA has estimated that the control measures used to meet Tier 4 standards will be integrated into the engine design so that sacrifices in fuel economy will be negligible.

[d]Some impact is expected but insufficient information is available to evaluate the impact.

[e]NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not known.

[f]For control measures reducing multiple pollutants, energy and other impacts are expressed as the impact per per total reduction of all pollutants. (However, EC, OC, and $PM_{2.5}$ are components of PM_{10}, and therefore are not added separately to the emission reduction total.)

[g]Some designs of low-NOX burners and ultralow-NOX burners require the use of pressurized air supplies. This would require additional electricity to pressurize the combustion air.

[h]Acid gas injection is also expected to result in sequestration of the CO_2 present in the acid gas stream.

4.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of oil and gas production and exploration equipment in the WRAP region. The remaining lifetime of most equipment is expected to be longer than the projected lifetime of pollution control technologies which have been analyzed for this category. In the case of add-on technologies, the projected lifetime is 15 years.

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

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5. Natural Gas Processing Operations

Natural gas processing facilities carry out a number of operations to remove impurities from natural gas before it is piped to consumers. In addition, the gas is typically fractionated to remove propane and heavier hydrocarbons, which are then processed as separate products. Emission sources at natural gas processing facilities include many of the same sources found at gas production operations, discussed in the previous chapter. Turbines and natural gas reciprocating engines are used to drive compressors and other equipment. Flares and incinerators are used to dispose of waste gases, and process heaters are used in various operations. In addition, emissions of SO_2 emanate from sulfur recovery operations at sour natural gas processing plants.

Table 5-1 summarizes emissions from the natural gas processing industry, broken down by state and by the various emission sources. Point source emissions of NO_X, SO_2, and VOC from these operations were extracted from the 2002 WRAP emissions inventory, which catalogs emission sources by their Standard Industrial Classification (SIC).[1] SIC 132 covers natural gas processing. Estimates for PM_{10} and $PM_{2.5}$ were extracted from the 2002 NEI, which also classifies emissions by SIC. It must be noted that the point source emissions in Table 5-1 for reciprocating engines and turbines in the natural gas processing industry are also included in the emission totals reported in Table 3-1 for all reciprocating engines and turbines. However, these emissions are separate from those reported in Table 4-1 for the oil and gas production and exploration sector.

Total NO_X emissions from natural gas processing are estimated at about 31,000 tons/year, and SO_2 emissions are estimated at about 12,000 tons/year. These emissions represent about 2% of stationary source (point and area source) NO_X emissions, and 1% of stationary source SO_2 emissions in the region.

PM_{10} and $PM_{2.5}$ emissions from natural gas processing facilities are estimated to be an order of magnitude lower than NO_X emissions. Emissions of OC and EC are not specifically quantified in either the WRAP inventory or the NEI, but can be estimated as a percentage of PM_{10} emissions using data from EPA's SPECIATE database.[2] EC and OC are estimated to comprise 38.4% and 24.7% of natural gas combustion PM_{10} emissions, respectively.

Emissions from individual reciprocating engines at natural gas processing plants range up to about 1,000 tons per year, compared with 1,373 tons per year for the largest natural gas fired reciprocating engines at industrial facilities. Emissions from individual turbines range up to 338 tons of NO_X per year, compared with 845 tons per year for the largest natural gas turbines at industrial facilities.[1]

Table 5-2 lists potential control measures for natural gas processing emissions. The table includes options for reciprocating engines and turbines, process heaters, flares and incinerators, and sulfur recovery units. As discussed in Chapter 3, a number of options are available to control emissions from gas-fired reciprocating engines, diesel-fueled reciprocating engines, and

Table 5-1. Emissions from Natural Gas Processing in the WRAP Region

Emission source	AK	CA	CO	MT	ND	NM	NV	UT	WY	Tribes	Total
NO_X emissions (tons/year)											
Reciprocating engines (natural gas)	86	626	1,027	33	2,428	15,976	0	612	1,935	1,140	23,863
Turbines	1,533	11	107	0	0	4,317	0	0	27	486	6,482
Process heaters	19	7	30	0	55	263	0	1	122	1	498
Boilers	1	29	60	0	0	193	0	20	6	26	335
Flares	0	14	1	0	0	56	0	1	25	0	97
Other[a]	0	14	5	0	10	122	0	1	82	0	234
Total	1,639	686	1,228	33	2,493	20,871	0	634	2,172	1,654	31,411
SO_2 emissions (tons/year)											
Sulfur recovery units	0	0	0	0	1,604	4,739	0	0	196	0	6,539
Flares	0	1	0	0	67	3,628	0	0	506	0	4,203
Incinerators	0	0	0	0	358	417	0	0	0	0	775
Process heaters	0	0	0	0	0	274	0	0	0	7	281
Other[a]	0	1	1	0	0	14	0	0	6	113	136
Total	0	2	1	0	2,030	9,072	0	0	708	119	11,934
PM_{10} emissions (tons/year)											
Reciprocating engines - natural gas	0	3	0	0	25	70	0	4	0	0	102
Other[a]	2	3	4	0	0	20	0	1	1	0	31
Total	2	6	4	0	25	90	0	5	1	0	134
$PM_{2.5}$ emissions (tons/year)											
Reciprocating engines - natural gas	0	3	0	0	25	70	0	3	0	0	102
Other[a]	2	3	4	0	0	19	0	1	1	0	30
Total	2	6	4	0	25	90	0	4	1	0	131
VOC emissions (tons/year)											
Storage	0	10	52,006	0	5	395	0	12	146	35	52,610
Reciprocating engines	0	687	102	20	44	1,135	0	13	278	29	2,308
Fugitive emissions	0	308	91	0	0	317	0	5	242	132	1,095
Glycol dehydrator	0	2	118	0	0	113	0	31	55	5	324
Turbines	10	0	0	0	0	187	0	0	0	21	219
Other[a]	1	89	210	0	2	54	0	90	35	35	515
Total	11	1,095	52,527	20	51	2,202	0	151	757	257	57,070

[a]Includes glycol dehydrator reboilers, incinerators, amine treatment units, and sources not specifically classified in the emissions inventory. For SO_2, incinerators are broken out separately.

Table 5-2. Control Options for Natural Gas Processing

Source Type	Control Technology	Pollutant controlled	Baseline emissions (1000 tons/yr)	Estimated control efficiency (%)	Potential emission reduction (1000 tons/year)	Refer-ences
Reciprocating engines, gas	Air-fuel ratio adjustment	NO_X	24	10 - 40	2 - 10	3,7
	Ignition timing retard	NO_X	24	15 - 30	4 - 7	3,7
	Low-emission combustion (LEC) retrofit	NO_X	24	80 - 90	19 - 21	4,7
	SCR	NO_X	24	90	21	7,8,12
	NSCR	NO_X	a	90 - 99	a	8
		VOC	a	40 - 85	a	8
	Replacement with electric motors	NO_X	24	100	24	7
		PM_{10}	0.10	100	0.10	
		$PM_{2.5}$	0.10	100	0.10	
		EC	0.04	100	0.04	
		OC	0.03	100	0.03	
		VOC	2	100	2	
		Overall[b]	26		26	
Turbines	Water or steam injection	NO_X	6.5	68 - 80	4.4 - 5.2	6
	Low-NO_X burner (LNB)	NO_X	6.5	68 - 84	4.4 - 5.4	6
	SCR	NO_X	6.5	90	5.8	5,6
	Water or steam injection with SCR	NO_X	6	93 - 96	6	6
Process heaters	Substitution of lower sulfur fuel	SO_2	0.28	up to 90	0 - 0.25	9,12
	LNB	NO_X	0.50	40	0.20	13,14
	ULNB	NO_X	0.50	75 - 85	0.37 - 0.42	12,13,14
	LNB and FGR	NO_X	0.50	48	0.24	13,14
	SNCR	NO_X	0.50	60	0.30	12,13,14
	SCR[c]	NO_X	0.50	70 - 90	0.35 - 0.45	12,13,14
	LNB and SCR	NO_X	0.50	70 - 90	0.35 - 0.45	12,13,14
Boilers	LNB with OFA	NO_X	0.33	30 - 50	0.1 - 0.17	11,12
	LNB, OFA, and FGR	NO_X	0.33	30 - 50	0.1 - 0.17	11,12
	SNCR	NO_X	0.33	30 - 75	0.1 - 0.25	11,12
	SCR	NO_X	0.33	40 - 90	0.13 - 0.3	11,12
Flares	Add or expand sulfur recovery unit	SO_2	4.2	90 - 95	d	9
	Acid gas injection	SO_2	4.2	100	d	10
Sulfur recovery units for amine treatment units	Additional recovery stages	SO_2	6.5	94 - 96	6.1 - 6.3	11,14
	Tail gas treatment unit (TGTU)	SO_2	6.5	90 - 99.5	5.9 - 6.5	11,14
Incinerators	Spray dryer absorber	SO_2	0.78	80 - 95	0.62 - 0.74	12
	Wet FGD	SO_2	0.78	90 - 99	0.7 - 0.77	11,12
	Acid gas injection	SO_2	0.78	100	d	10
Glycol dehydrators	Optimize glycol circulation rate	VOC	0.32	33 - 67	0.11 - 0.22	7

[a]NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not

[b]For control measures reducing multiple pollutants, overall emissions and emission reductions reflect the sum of all pollutants. However, EC, OC, and PM2.5 are components of PM10, and therefore are not added separately to the totals.

[c]SCR can be used for mechanical draft process heaters. Natural draft heaters would have to be converted to mechanical draft for installation of SCR.

[d]Insufficient information is available in the emissions inventory to determine the percentage of flare or incinerator emissions in this category that is amenable to these control strategies.

turbines.[3,4,5,6,7,8] Reciprocating engines can be designed to operate under rich fuel mixture, or lean fuel mixture conditions. Air-to-fuel-ratio adjustments and ignition retarding technologies can be used to control emissions under either fuel mixture condition. Low-Emission Combustion (LEC) retrofit technology can also reduce emissions from lean burn reciprocating engines by an average of 89%. LEC involves modifying the combustion system to achieve very lean combustion conditions (high air-to-fuel ratios). Selective Catalytic Reduction (SCR) can also be used either alone or in conjunction with the above technologies to reduce NO_X emissions from reciprocating engines or turbines by 90%. In addition, Non-Selective Catalytic Reduction (NSCR) can be used for rich-burn natural gas engines.[8]

SO_2 emissions from incinerators and flares could be reduced by installing sulfur recovery units to remove sulfur from the waste gases prior to incineration or flaring.[9] These emissions can also be reduced by compressing sulfur-containing acid gases and injecting these gases into non-producing rock formations.[10] Flue gas scrubbing has also been used to control SO_2 emissions from incinerators.[11,12] SO_2 emissions from existing sulfur recovery units can be reduced by adding additional recovery stages, or by adding a tail gas treatment unit.[12] In some cases, it may be possible to avoid SO_2 emissions from process heaters by substituting a lower-sulfur sweetened natural gas for the gas currently being burned. A number of options are available to reduce NO_X emissions from process heaters. Combustion modifications including LNB, ULNB, and FGR reduce the formation of NO_X. In addition, flue gases from the process heaters can be treated with SCR or SNCR to reduce NO_X emissions. These post-combustion controls can be used either alone or in conjunction with combustion controls.[13,14]

5.1 Factor 1 – Costs

Table 5-3 provides cost estimates for the emission control options which have been identified for the natural gas processing industry. 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 and annual cost figures are expressed in terms of the cost per unit of engine size or per unit of process throughput. Engine size is expressed in horsepower for reciprocating engines and MMBtu/hour for turbines. Throughput for process heaters is also expressed in MMBtu/hour. Process throughput for sulfur recovery units is expressed in terms of the amount of sulfur recovered.

Sulfur recovery units are believed to be more cost-effective than post-combustion controls for reducing SO_2 emissions from flares and incinerators at natural gas processing facilities. Recent analyses of controls for Regional Haze precursors have focused on add-on controls for SO_2, rather than such process modifications. However, costs of sulfur recovery units were estimated in an earlier study of model refineries in different size ranges.[9] These estimates have been updated to current dollars using the Chemical Engineering plant cost index.

Table 5-3 shows a range of values for each cost figure, since the cost per unit of throughput will depend on the engine or process size and other factors. The lower ends of the cost ranges typically reflect larger engine or process sizes, and the higher ends of the cost ranges typically reflect smaller engine or process sizes. The table also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

5.2 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 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control.[15] However, the time necessary will depend on the type and size of the unit being controlled. For instance, state regulators' experience indicates that closer to 18 months is required to install this technology.[16] In the CAIR analysis, EPA estimated that approximately 30 months is required to design, build, and install SO_2 scrubbing technology for a single emission source.[17] 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 achieve emission reductions for natural gas processing facilities is estimated at a total of 6½ years.

5.3 Factor 3 – Energy and Other Impacts

Table 5-4 shows the estimated energy and non-air pollution impacts of control measures for sources at natural gas processing facilities. For gas-fired reciprocating engines and diesel engines, air-to-fuel-ratio adjustments and ignition retarding technologies have been found to increase fuel consumption by up to 5%, with a typical value of about 2.5%.[18,19] This increased fuel consumption would result in increased CO_2 emissions. LEC technology is not expected to increase fuel consumption; and may provide some fuel economy.[18]

For turbines, water injection and steam injection would require electricity to operate pumps and ancillary equipment.[13] Water injection would produce an increase in fuel consumption in order to evaporate the water, and steam injection would require energy to produce the steam. The increased electricity, steam, and fuel demands would produce additional CO_2 emissions.

Installation of SCR on any type of engine would cause a small increase in fuel consumption, about 0.5%, in order to force the exhaust gas through the catalyst bed.[18] This would 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.[13]

Table 5-3. Estimated Costs of Control for Natural Gas Processing

Source Type	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Estimated capital cost ($/unit)	Estimated annual cost ($/year /unit)	Units	Cost effectiveness ($/ton)	Refer-ences
Reciprocating engines, gas	Air-fuel ratio adjustment	NO_X	10 - 40	5.3 - 42	0.9 - 6.8	hp	68 - 2,500	3,7
	Ignition timing retard	NO_X	15 - 30	na	1 - 3	hp	42 - 1,200	3,7
	LEC retrofit	NO_X	80 - 90	120 - 820	30 - 210	hp	320 - 2,500	4,7
	SCR	NO_X	90	100 - 450	40 - 270	hp	870 - 31,000	7,8,12
	NSCR[a]	NO_X	90 - 99	17 - 35	3 - 6	hp	16 - 36	4
		VOC	40 - 85				1,500 - 6,200	4
		Overall[b]					16 - 36	
	Replacement with electric motors	all[b]	100	120 - 140	38 - 44	hp	100 - 4,700	7
Turbines	Water or steam injection	NO_X	68 - 80	4.4 - 16	2 - 5	1000 Btu/hr	560 - 3,100	6
	Low-NO_X burners[c]	NO_X	68 - 84	8 - 22	2.7 - 8.5	1000 Btu/hr	5,200 - 16,200	6
	SCR	NO_X	90	13 - 34	5.1 - 13	1000 Btu/hr	1,000 - 6,700	5,6
	Water or steam injection with SCR	NO_X	93 - 96	13 - 34	5.1 - 13	1000 Btu/hr	1,000 - 6,700	6
Process heaters	Substitution of lower sulfur fuel	SO_2	up to 90					9,12
	LNB	NO_X	40	3.8 - 7.6	0.41 - 0.81	1000 BTU	2,100 - 2,800	13,14
	ULNB	NO_X	75 - 85	4.0 - 13	0.43 - 1.3	1000 BTU	1,500 - 2,000	12,13,14
	LNB and FGR	NO_X	48	16	1.7	1000 BTU	2,600	13,14
	SNCR	NO_X	60	10 - 22	1.1 - 2.4	1000 BTU	4,700 - 5,200	12,13,14
	SCR[d]	NO_X	70 - 90	33 - 48	3.7 - 5.6	1000 BTU	2,900 - 6,700	12,13,14
	LNB and SCR	NO_X	70 - 90	37 - 55	4 - 6.3	1000 BTU	2,900 - 6,300	12,13,14
Boilers	LNB with OFA	NO_X	30 - 50				500 - 5,300	11,12
	LNB, OFA, and FGR	NO_X	30 - 50				500 - 11,000	11,12
	SNCR	NO_X	30 - 75				400 - 2,500	11,12
	SCR	NO_X	40 - 90				2,400 - 7,200	11,12
Flares	Add or expand sulfur recovery unit	NO_X	90 - 95	0.1 - 1.1	28 - 190	ton-Sulfur/year	14 - 95	9
	Acid gas injection	SO_2	95					10
Sulfur recovery units for amine treatment units	Additional recovery stages	SO_2	94 - 96	0.1 - 1	28 - 150	ton-Sulfur/year	14 - 75	9
	Tail gas treatment unit (TGTU)	SO_2	90 - 99.5	0.3 - 1.1	67 - 190	ton-Sulfur/year	33 - 95	9
Incinerators	Spray dryer absorber	SO_2	80 - 95				1,500-1,900	12
	Wet FGD	SO_2	90 - 99				1,500 - 1,800	11,12
	Acid gas injection	SO_2	100					10
Glycol dehydrators	Optimize glycol circulation rate	VOC	33 - 67	31 - 170	5 - 28	gal/hr		7

[a]NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not known.

[b]For control measures reducing multiple pollutants, the overall cost-effectiveness is the cost per total reduction of all pollutants. However, EC, OC, and PM2.5 are components of PM10, and therefore are not added separately to the emission reduction total.

[c]Costs estimates for low-NO_X burners for turbines reflect the incremental costs of new low-NO_X burners versus standard burners. Retrofit costs for existing burners were not available.

[d]SCR cost estimates for process heaters apply to mechanical draft heaters. Natural draft heaters would have to be converted to mechanical draft for installation of SCR. This would increase both the capital and annualized costs of control by about 10%.

Table 5-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Natural Gas Processing

					Energy and non-air pollution impacts (per ton of emission reduced)				
Source Type	Control Technology	Pollutant controlled	Potential emission reduction (1000 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)
Reciprocating engines	Air-fuel ratio controllers	NO_X	2 - 10	a					
	Ignition timing retard	NO_X	4 - 7	a					
	LEC retrofit	NO_X	19 - 21	a					
	SCR	NO_X	21	0.5			0.008		0.43
	NSCR	NO_X, VOC	e	0.5			0.008		0.24
	Replacement with electric motors	NO_X	24	(100)	66,000				b
Turbines	Water or steam injection	NO_X	4.4 - 5.2	a		31			8.1
	Low-NO_X burner (LNB)	NO_X	4.4 - 5.4	a					
	SCR	NO_X	5.8	0.45			0.026		1.7
	Water or steam injection with SCR	NO_X	6	0.45			0.026		1.7
Process heaters	Substitution of lower sulfur fuel	SO_2	0 - 0.25						
	LNB	NO_X	0.2	a	f				
	ULNB	NO_X	0.37 - 0.42	a	f				
	LNB and FGR	NO_X	0.24		3,300				3.3
	SNCR	NO_X	0.3	0.16	460				3.2
	SCR	NO_X	0.35 - 0.45		8,400		0.073		8.4
	LNB and SCR	NO_X	0.35 - 0.45		8,400		0.073		8.4
Boilers	LNB with OFA	NO_X	0.1 - 0.17	a					
	LNB, OFA, and FGR	NO_X	0.1 - 0.17		3,300				3.3
	SNCR	NO_X	0.1 - 0.25	0.16	460				3.2
	SCR	NO_X	0.13 - 0.3		8,400		0.073		8.4
Flares	Add or expand sulfur recovery unit	SO_2	up to 4.2		270	3.2	<0.01		1.1
	Acid gas injection	SO_2	up to 4.2	d					g
Sulfur recovery units for gas sweetening units	Additional recovery stages	SO_2	6.1 - 6.3		270	3.2	<0.01		1.1
	Tail gas treatment unit (TGTU)	SO_2	5.9 - 6.5		190	3.5		3.7	1.1
Incinerators	Spray dryer absorber	SO_2	0.62 - 0.74		400				1.1
	Wet FGD	SO_2	0.7 - 0.77		1,100	3.1		3.7	2.6
	Acid gas injection	SO_2	up to 0.78	d					g
Glycol dehydrators	Optimize glycol circulation rate	VOC	0.11 - 0.22	a					

NOTES:

blank indicates no impact is expected.

[a]The measure is expected to improve fuel efficiency.

[b]CO_2 from the generation of electricity would be offset by avoided emissions due to replacing the diesel engine

[c]EPA has estimated that the control measures used to meet Tier 4 standards will be integrated into the engine design so that sacrifices in fuel economy will be negligible.

[d]Some impact is expected but insufficient information is available to evaluate the impact.

[e]NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not known.

[f]Some designs of low-NOX burners and ultralow-NOX burners require the use of pressurized air supplies. This would require additional electricity to pressurize the combustion air.

[g]Acid gas injection is also expected to result in sequestration of the CO_2 present in the acid gas stream.

Sulfur recovery units require electricity and steam. Wet or dry scrubbers applied to incinerators and tail gas treatment units applied to sulfur recovery units would use electricity for the fan power needed to overcome the scrubber pressure drop. These systems would also produce solid waste, and wet scrubbers would produce wastewater which would require treatment. Injection of acid gases would require the consumption of fuel to compress the gases. However, this option would also result in the sequestration of CO_2 present in the injected gas stream.[10]

Low-NO_X burners for process heaters are expected to improve overall fuel efficiency. FGR would require additional electricity to recirculate the fuel gas into the heater. In SCR systems for process heaters, fans would be required to overcome the pressure drop through the catalyst bed. The fans would require electricity, with resultant increases in CO_2 to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal. [13]

5.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of natural gas processing equipment in the WRAP region. The remaining lifetime of most equipment is expected to be longer than the projected lifetime of pollution control technologies which have been analyzed for this category. In the case of add-on technologies, the projected lifetime is 15 years.

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

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6. Industrial Boilers

Industrial boilers encompass the category of boilers used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity. There are no specific size definitions for an industrial boiler, however for the purposes of this document, the definition described in Subpart Db of 40 CFR Part 60, New Source Performance Standards (NSPS) for Industrial, Commercial, and Institutional Steam Generating Units will be used. This NSPS regulates steam generating units with a heat input capacity between 100 to 250 MMBtu/hr (29 - 73 MW). Steam generating units greater than 250 MMBtu/hr (73 MW) are subject to the requirements of Subpart D of 40 CFR Part 60.

An industrial boiler report[1] estimated that there are approximately 43,000 industrial boilers operating in the U.S. with an aggregate capacity of 1.5 million MMBtu/hr input. The report noted that approximately half of these industrial boilers are less than 10 MMBtu/hr in size, but account for only 7% of the total capacity. The 2002 WRAP stationary point source emissions tables[2] lists a total of 2,171 facilities with industrial boilers in the 102XXX Source Classification Code (SCC). The majority of the boilers are located at facilities in the food, paper, chemicals, refining and primary metals industries. The most common fuel used for combustion is natural gas with nearly 73% of the facilities in the WRAP region operating natural gas-fired industrial boilers.

Industrial boilers in the WRAP region are estimated to emit about 43,060 tons of NO_X and 28,155 tons of SO_2, based on the 2002 emissions inventory for the region.[3] These boilers utilize the combustion of fuel which includes; coal, oil, natural gas, waste, and wood, to produce steam. Coal-fired industrial boilers comprise of 15,920 tons of NO_X, or 37% of the total NO_X emissions, and 14,376 tons, or 51% of the total SO_2 emissions from industrial boilers in the WRAP region. Industrial boilers represent about 4.1% of the total point source emissions of NO_X, and about 3.4% of the total SO_2 point source emissions in the WRAP region.

Table 6-1 shows estimated emissions of NO_X, SO_2, PM_{10}, $PM_{2.5}$, and VOC from the WRAP emissions inventory, broken down by state and fuel. The table shows that PM_{10}, $PM_{2.5}$, and VOC emissions from industrial boilers are significantly lower than the NO_X and SO_2 emissions. Emissions of PM from these sources were not included in the inventory, but are expected to be much lower than the NO_X and SO_2 emissions. As the table shows, coal-fired boilers were the most significant source of NO_X, SO_2, and VOC emissions in the WRAP region. For NO_X, coal fired boilers accounted for about 56% of the emissions from point sources, and 41% of the total stationary source emissions in the WRAP region.

Table 6-2a lists potential control measures for NO_X, SO_2, PM_{10}, $PM_{2.5}$, EC, and OC emissions from coal-fired and oil-fired industrial boilers. Table 6-2b presents control options for natural gas boilers, and Table 6-2c provides control options for wood-fired industrial boilers for each of these pollutants. Uncontrolled emission rates were obtained from the respective AP-42 section for each of the fuels.[4] Control technology options were identified using information from industrial boiler control option studies.[5] The control options were divided into appropriate control technologies for each of the four fuels; coal, oil, natural gas, and wood.

Table 6-2d lists potential control options for NO_X, SO_2, PM_{10}, $PM_{2.5}$, EC, and OC coal-fired and oil-fired industrial boilers by age. These pollutants are regulated under the Clean Air Act (CAA) to attain and maintain National Ambient Air Quality Standards (NAAQS), reduce acidic deposition, and improve visibility under regional haze regulations. To attain and maintain the NAAQS, the EPA enacted the Prevention of Significant Deterioration (PSD) regulations to establish maximum pollution concentration levels to protect public health and welfare from harmful levels of pollutants. The PSD regulations require new major sources or major modifications at existing sources to install "Best Available Control Technology (BACT)" and conduct ambient air quality analyses to show that the new source or modification will not cause or contribute to a violation of any applicable NAAQS or PSD increment. Because PSD requirements are on a case-by-case basis, the age groups were segregated into using the New Source Performance Standards (NSPS) to show control options and emission levels for coal-fired and oil-fired industrial boilers. The age groups are designated as pre-NSPS, post-NSPS, and post CAA amendments of 1990.

Table 6-1. Emissions from Industrial Boilers in the WRAP Region

Emission source	AK	AZ	CA	CO	ID	MT	ND	NM	NV	OR	SD	UT	WA	WY	Tribes	Total
							NO_X emissions (tons/year)									
Coal-fired Boilers	1,823	0	1,366	336	3,268	366	1,264	0	0	0	0	2,412	49	5,036	0	15,920
Natural gas-fired Boilers	260	786	5,555	2,706	1,184	726	140	764	114	370	224	764	2,435	685	26	16,740
Oil-fired Boilers	67	7	86	44	42	118	0	0	26	41	0	78	478	5	10	1,004
Waste-fired Boilers	0	0	49	0	480	214	94	0	0	1	0	0	72	0	0	910
Wood-fired Boilers	0	0	2,089	7	349	1,999	0	0	0	70	89	0	2,988	10	525	8,126
Total	2,150	793	9,145	3,093	5,323	3,424	1,498	765	140	481	313	3,255	6,022	5,736	561	42,700
							SO_2 emissions (tons/year)									
Coal-fired Boilers	1,421	0	139	24	2,976	128	1,284	0	0	0	0	2,831	62	5,511	0	14,376
Natural gas-fired Boilers	7	5,668	969	138	6	1	3	9	11	2	497	435	1,113	544	0	9,403
Oil-fired Boilers	55	6	127	25	113	1,241	0	3	77	234	0	52	1,444	1	14	3,391
Waste-fired Boilers	0	0	2	0	8	46	14	0	0	16	0	0	5	0	0	91
Wood-fired Boilers	0	0	161	0	7	54	0	0	0	3	6	0	622	2	33	887
Total	1,483	5,674	1,396	187	3,109	1,470	1,301	12	89	255	503	3,319	3,245	6,058	47	28,147
							PM_{10} emissions (tons/year)									
Coal-fired Boilers	0	19	37	7	468	36	12	0	0	100	0	100	0	581	0	1,361
Natural gas-fired Boilers	11	5	82	22	14	2	2	8	5	13	3	13	19	7	0	207
Oil-fired Boilers	2	2	16	3	4	54	0	0	77	26	0	1	223	79	0	488
Waste-fired Boilers	0	0	0	0	44	136	0	0	0	33	0	0	25	0	0	238
Wood-fired Boilers	0	0	671	6	41	267	0	0	0	2,025	75	0	1,035	0	0	4,119
Total	13	26	806	38	571	495	14	8	82	2,196	79	115	1,302	667	0	6,413
							$PM_{2.5}$ emissions (tons/year)									
Coal-fired Boilers	0	3	28	1	255	27	2	0	0	63	0	43	0	123	0	543
Natural gas-fired Boilers	10	4	78	22	12	2	2	7	4	12	3	10	17	6	0	190
Oil-fired Boilers	2	1	14	3	3	45	0	0	49	2	0	1	149	49	0	318
Waste-fired Boilers	0	0	0	0	2	83	0	0	0	27	0	0	25	0	0	136
Wood-fired Boilers	0	0	625	4	41	229	0	0	0	1,776	12	0	646	0	0	3,333
Total	12	8	745	29	312	386	3	7	53	1,880	15	55	837	178	0	4,520
							VOC emissions (tons/year)									
Coal-fired Boilers	6	0	3	4	31	0	9	0	0	0	0	12	0	10	0	76
Natural gas-fired Boilers	11	205	316	193	44	14	5	33	15	11	15	39	80	19	1	1,001
Oil-fired Boilers	3	0	2	1	1	0	0	0	9	1	0	1	9	1	0	28
Waste-fired Boilers	0	0	5	0	116	59	31	0	0	0	0	0	62	0	0	273
Wood-fired Boilers	0	0	373	0	15	511	0	0	0	23	47	0	284	0	110	1,363
Total	21	205	697	198	208	583	46	33	24	35	62	53	435	30	111	2,741

Table 6-2a. Control Options for Coal-Fired and Oil-Fired Industrial Boilers

Source Type	Pollutant controlled	Control Technology	Uncontrolled emissions[1,2] (lb/MMBtu)	Estimated control efficiency (%)	Potential controlled emissions (lb/MMBtu)	References
Coal-fired	NO_X	LNB	1.3	50	0.63	4, 5, 7, 9
		LNB w/OFA	1.3	50 - 65	0.63 - 0.46	4, 5, 7, 9
		SNCR	1.3	30 - 75	0.91 - 0.33	4, 5, 7, 9
		SCR	1.3	40 - 90	0.78 - 0.13	4, 5, 7, 9
	SO_2	Physical coal cleaning	1.3	10 - 40	1.2 - 0.78	4, 5, 8, 9
		Chemical coal cleaning	1.3	50 - 85	0.63 - 0.20	4, 5, 8, 9
		Use lower sulfur fuel	1.3	20 - 90	1.0 - 0.13	4, 5, 8, 9
		Dry sorbent injection	1.3	50 - 90	0.63 - 0.13	4, 5, 8, 9
		Spray dryer absorber	1.3	90	0.13	4, 5, 8, 9
		Wet FGD	1.3	90	0.13	4, 5, 8, 9
	$PM_{2.5}$, PM_{10}, EC, OC	Fabric filter	1.5	99.3	0.011	4, 5, 9
		ESP	1.5	99.3	0.011	4, 5, 9
Oil-fired	NO_X	LNB	0.34	40	0.20	4, 5, 7, 9
		LNB w/ OFA	0.34	30 - 50	0.24 - 0.17	4, 5, 7, 9
		LNB w/ OFA and FGR	0.34	30 - 50	0.24 - 0.17	4, 5, 7, 9
		SNCR	0.34	30 - 75	0.24 - 0.085	4, 5, 7, 9
		SCR	0.34	40 - 90	0.20 - 0.034	4, 5, 7, 9
	SO_2	Use lower sulfur fuel	0.67	20 - 90	0.54 - 0.067	4, 5, 8, 9
		Spray dryer absorber	0.67	90	0.067	4, 5, 8, 9
		Wet FGD	0.67	90	0.067	4, 5, 8, 9
	$PM_{2.5}$, PM_{10}, EC, OC	Fabric filter	0.044	95.8	0.0018	4, 5, 9
		ESP	0.044	95.8	0.0018	4, 5, 9

[1] Uncontrolled coal-fired emission rates calculated using AP-42 emission factors for PC, dry bottom, wall-fired, bituminous Pre-NSPS. The emission factor was converted to lb/MMBtu assuming MT coal with a heat rate of 17.5 MMBtu/ton, a sulfur content of 0.62 weight percent sulfur, and an ash content of 11.5 percent.

[2] Uncontrolled oil-fired emission rates calculated using AP-42 emission factors for No. 6 oil fired, normal firing. The emission factor was converted to lb/MMBtu assuming a distillate oil heat content of 140,000 Btu/gal, and a sulfur content of 0.60 weight percent sulfur.

Table 6-2b. Control Options for Industrial Natural Gas-Fired Boilers

Source Type	Pollutant controlled	Control Technology	Uncontrolled emissions[1] (lb/MMBtu)	Estimated control efficiency (%)	Potential controlled emissions (lb/MMBtu)	References
Natural gas-fired	NO_X	LNB	0.27	40	0.16	4, 5, 7, 9
		LNB w/ OFA	0.27	40 - 60	0.11 - 0.16	4, 5, 7, 9
		LNB w/ OFA and FGR	0.27	40 - 80	0.05 - 0.16	4, 5, 7, 9
		SNCR	0.27	30 - 75	0.19 - 0.07	4, 5, 7, 9
		SCR	0.27	70 - 90	0.08 - 0.03	4, 5, 7, 9

[1] Uncontrolled natural gas-fired emission rates calculated using AP-42 emission factors for Large Wall-Fired Boilers, >100 MMBtu/hr, Uncontrolled (Pre-NSPS).

Table 6-2c. Control Options for Industrial Wood-Fired Boilers

Source Type	Pollutant controlled	Control Technology	Uncontrolled emissions[1] (lb/MMBtu)	Estimated control efficiency (%)	Potential controlled emissions (lb/MMBtu)	References
Wood-fired	NO_X	SNCR	0.49	30 - 75	0.12 - 0.34	4, 5, 7, 9
		SCR	0.49	40 - 90	0.05 - 0.29	4, 5, 7, 9
	$PM_{2.5}$, PM_{10}	Fabric filter	0.36	95.8	0.015	4, 5, 9
		ESP	0.36	95.8	0.015	4, 5, 9

[1] Uncontrolled wood-fired emission rates calculated using AP-42 emission factors for uncontrolled dry wood combustion.

Table 6-2d. Control Options for Industrial Coal-Fired and Oil-Fired Boilers

Source Type	Pollutant controlled	Control Technology	Uncontrolled emissions[1,2] (lb/MMBtu)	Estimated control efficiency (%)	Potential controlled emissions (lb/MMBtu)	References
Coal-fired (Pre PSD Regulations)[1]	NO_X	LNB	1.3	50	0.63	4, 5, 7, 9
		LNB w/OFA	1.3	50 - 65	0.63 - 0.46	4, 5, 7, 9
		SNCR	1.3	30 - 75	0.91 - 0.33	4, 5, 7, 9
		SCR	1.3	40 - 90	0.78 - 0.13	4, 5, 7, 9
	SO_2	Physical coal cleaning	1.3	10 - 40	1.2 - 0.78	4, 5, 8, 9
		Chemical coal cleaning	1.3	50 - 85	0.63 - 0.20	4, 5, 8, 9
		Use lower sulfur fuel	1.3	20 - 90	1.0 - 0.13	4, 5, 8, 9
		Dry sorbent injection	1.3	50 - 90	0.63 - 0.13	4, 5, 8, 9
		Spray dryer absorber	1.3	90	0.13	4, 5, 8, 9
		Wet FGD	1.3	90	0.13	4, 5, 8, 9
	$PM_{2.5}$, PM_{10}, EC, OC	Fabric filter	1.5	99.3	0.011	4, 5, 9
		ESP	1.5	99.3	0.011	4, 5, 9
Oil-fired (Pre PSD Regulations)[2]	NO_X	LNB	0.34	40	0.20	4, 5, 7, 9
		LNB w/ OFA	0.34	30 - 50	0.24 - 0.17	4, 5, 7, 9
		LNB w/ OFA and FGR	0.34	30 - 50	0.24 - 0.17	4, 5, 7, 9
		SNCR	0.34	30 - 75	0.24 - 0.085	4, 5, 7, 9
		SCR	0.34	40 - 90	0.20 - 0.034	4, 5, 7, 9
	SO_2	Use lower sulfur fuel	0.67	20 - 90	0.54 - 0.067	4, 5, 8, 9
		Spray dryer absorber	0.67	90	0.067	4, 5, 8, 9
		Wet FGD	0.67	90	0.067	4, 5, 8, 9
	$PM_{2.5}$, PM_{10}, EC, OC	Fabric filter	0.044	95.8	0.0018	4, 5, 9
		ESP	0.044	95.8	0.0018	4, 5, 9
Coal-fired (Post PSD Regulations)[3]	NO_X	LNB	0.69	50	0.34	4, 5, 7, 9
		LNB w/OFA	0.69	50 - 65	0.34 - 0.24	4, 5, 7, 9
		SNCR	0.69	30 - 75	0.48 - 0.17	4, 5, 7, 9
		SCR	0.69	40 - 90	0.41 - 0.069	4, 5, 7, 9
	SO_2	Physical coal cleaning	1.3	10 - 40	1.2 - 0.78	4, 5, 8, 9
		Chemical coal cleaning	1.3	50 - 85	0.63 - 0.20	4, 5, 8, 9
		Use lower sulfur fuel	1.3	20 - 90	1.0 - 0.13	4, 5, 8, 9
		Dry sorbent injection	1.3	50 - 90	0.63 - 0.13	4, 5, 8, 9
		Spray dryer absorber	1.3	90	0.13	4, 5, 8, 9
		Wet FGD	1.3	90	0.13	4, 5, 8, 9
	$PM_{2.5}$, PM_{10}, EC, OC	Fabric filter	1.5	99.3	0.011	4, 5, 9
		ESP	1.5	99.3	0.011	4, 5, 8
Oil-fired (Post PSD Regulations)[4]	NO_X	LNB	0.34	40	0.20	4, 5, 7, 9
		LNB w/ OFA	0.34	30 - 50	0.24 - 0.17	4, 5, 7, 9
		LNB w/ OFA and FGR	0.34	30 - 50	0.24 - 0.17	4, 5, 7, 9
		SNCR	0.34	30 - 75	0.24 - 0.085	4, 5, 7, 9
		SCR	0.34	40 - 90	0.20 - 0.034	4, 5, 7, 9
	SO_2	Use lower sulfur fuel	0.67	20 - 90	0.54 - 0.067	4, 5, 8, 9
		Spray dryer absorber	0.67	90	0.067	4, 5, 8, 9
		Wet FGD	0.67	90	0.067	4, 5, 8, 9
	$PM_{2.5}$, PM_{10}, EC, OC	Fabric filter	0.044	95.8	0.0018	4, 5, 9
		ESP	0.044	95.8	0.0018	4, 5, 9

Table 6-2d. Control Options for Industrial Coal-Fired and Oil-Fired Boilers (cont.)

Source Type	Pollutant controlled	Control Technology	Uncontrolled emissions[1,2] (lb/MMBtu)	Estimated control efficiency (%)	Potential controlled emissions (lb/MMBtu)	References
Coal-fired (Post Clean Air Act Amendments of 1990)[5]	NO_X	LNB	0.50	50	0.25	4, 5, 7, 9
		LNB w/OFA	0.50	50 - 65	0.25 - 0.18	4, 5, 7, 9
		SNCR	0.50	30 - 75	0.35 - 0.13	4, 5, 7, 9
		SCR	0.50	40 - 90	0.30 - 0.050	4, 5, 7, 9
	SO_2	Physical coal cleaning	0.20	10 - 40	0.18 - 0.12	4, 5, 8, 9
		Chemical coal cleaning	0.20	50 - 85	0.10 - 0.030	4, 5, 8, 9
		Use lower sulfur fuel	0.20	20 - 90	0.16 - 0.020	4, 5, 8, 9
		Dry sorbent injection	0.20	50 - 90	0.10 - 0.020	4, 5, 8, 9
		Spray dryer absorber	0.20	90	0.02	4, 5, 8, 9
		Wet FGD	0.20	90	0.02	4, 5, 8, 9
	$PM_{2.5}$, PM_{10}, EC, OC	Fabric filter	0.05	99.3	0.00035	4, 5, 9
		ESP	0.05	99.3	0.00035	4, 5, 9
Oil-fired (Post Clean Air Act Amendments of 1990)[5]	NO_X	LNB	0.20	40	0.12	4, 5, 7, 9
		LNB w/ OFA	0.20	30 - 50	0.14 - 0.10	4, 5, 7, 9
		LNB w/ OFA and FGR	0.20	30 - 50	0.14 - 0.10	4, 5, 7, 9
		SNCR	0.20	30 - 75	0.14 - 0.050	4, 5, 7, 9
		SCR	0.20	40 - 90	0.12 - 0.020	4, 5, 7, 9
	SO_2	Use lower sulfur fuel	0.50	20 - 90	0.40 - 0.005	4, 5, 8, 9
		Spray dryer absorber	0.50	90	0.050	4, 5, 8, 9
		Wet FGD	0.50	90	0.050	4, 5, 8, 9
	$PM_{2.5}$, PM_{10}, EC, OC	Fabric filter	0.044	95.8	0.0018	4, 5, 9
		ESP	0.044	95.8	0.0018	4, 5, 9

[1] Uncontrolled coal-fired emission rates calculated using AP-42 emission factors for PC, dry bottom, wall-fired, bituminous Pre-NSPS. The emission factor was converted to lb/MMBtu assuming MT coal with a heat rate of 17.5 MMBtu/ton, a sulfur content of 0.62 weight percent sulfur, and an ash content of 11.5 percent.

[2] Uncontrolled oil-fired emission rates calculated using AP-42 emission factors for No. 6 oil fired, normal firing. The emission factor was converted to lb/MMBtu assuming a distillate oil heat content of 140,000 Btu/gal, and a sulfur content of 0.60 weight percent sulfur.

[3] Uncontrolled coal-fired emission rates calculated using AP-42 emission factors for PC, dry bottom, wall-fired, bituminous Post-NSPS. The emission factor was converted to lb/MMBtu assuming MT coal with a heat rate of 17.5 MMBtu/ton, a sulfur content of 0.62 weight percent sulfur, and an ash content of 11.5 percent.

[4] Uncontrolled oil-fired emission rates calculated using AP-42 emission factors for No. 6 oil fired, normal firing. The emission factor was converted to lb/MMBtu assuming a distillate oil heat content of 140,000 Btu/gal, and a sulfur content of 0.60 weight percent sulfur.

[5] Uncontrolled Coal fired and oil-fired emission rates are base the the 40 CFR 60, Subpart Db limits for each of the fuels.

6.1 Factor 1 – Costs

Table 6-3 provides cost estimates for the emission control options which have been identified for each of the industrial 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 heat input (MMBtu/hr) to the boiler. The annual cost is presented in millions of dollars per year. The table shows a range of values for each cost figure, since the capital cost will depend on the rated heat input to the boiler and other factors. The lower ends of the capital and annual cost ranges typically reflect smaller sized boilers, and the higher ends of the capital and annual cost ranges reflect larger sized boilers. Table 3-3 also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction. Lower cost effectiveness values generally reflect the larger heat input boiler sizes, whereas higher cost effectiveness values reflect lower heat input boilers sizes.

6.2 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.

6.3 Factor 3 – Energy and Other Impacts

Table 6-4 shows the estimated energy and non-air pollution impacts of control measures for industrial boilers. The values were obtained from a report summarizing the applicability and feasibility of control options for industrial boilers.[8] In general, the combustion modification technologies (LNB, OFA, FGR) do not require steam or generate solid waste, wastewater, or additional CO_2. 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.

Table 6-3. Estimated Costs of Control for Industrial Boilers

Source Type	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Estimated capital cost ($/MMBtu/hr)	Estimated annual cost ($M)	Cost effectiveness ($/ton)	References
Coal-fired	LNB	NO_X	50	3,435 - 6,856	0.175 - 0.317	344 - 4,080	5, 7, 9
	LNB w/OFA		50 - 65	4,908 - 9,794	NA	412 - 4,611	5, 7, 9
	SNCR		30 - 75	3,550 - 7,083	0.333 - 0.419	1,728 - 6,685	5, 7, 9
	SCR		40 - 90	9,817 - 19,587	0.738 - 1.32	1,178 - 7,968	5, 7, 9
	Physical coal cleaning	SO_2	10 - 40	NA	NA	70 - 563	5, 8, 9
	Chemical coal cleaning		50 - 85	NA	NA	1,699 - 2,561	5, 8, 9
	Use lower sulfur fuel		20 - 90	NA	NA		5, 8, 9
	Dry sorbent injection		50 - 90	11,633 - 36,096	NA	851 - 5,761	5, 8, 9
	Spray dryer absorber		90	27,272 - 73,549	7.93 - 9.26	3,885 - 8,317	5, 8, 9
	Wet FGD		90	40,203 - 86,410	10.10 - 11.71	4,687 - 10,040	5, 8, 9
	Fabric filter	$PM_{2.5}$, PM_{10}	99.3	20,065 - 30,287	0.82 - 1.39	406 - 592	5, 6, 9
	ESP		99.3	17,037 - 24,293	0.66 - 1.17	342 - 485	5, 6, 9
Oil-fired	LNB	NO_X	40	1,205 - 2,405	0.190 - 0.346	412 - 7,075	5, 7, 9
	LNB w/ OFA		30 - 50	1,722 - 3,435	NA	412 - 7,075	5, 7, 9
	LNB w/ OFA and FGR		30 - 50	2,690 - 5,368	NA	439 - 6,689	5, 7, 9
	SNCR		30 - 75	2,840 - 5,666	0.206 - 0.355	1,997 - 9,952	5, 7, 9
	SCR		40 - 90	5,399 - 10,773	0.484 - 0.831	1,022 - 24,944	5, 7, 9
	Use lower sulfur fuel	SO_2	20 - 90	NA	NA	5611	5, 8, 9
	Spray dryer absorber		90	119,731 - 270,514	7.72 - 8.80	4,947 - 10,887	5, 8, 9
	Wet FGD		90	36,930 - 73,660	9.85 - 11.29	6,008 - 13,156	5, 8, 9
	Fabric filter	$PM_{2.5}$, PM_{10}	95.8	17,205 - 26,291	0.72 - 1.20	7,298 - 10,889	5, 6, 9
	ESP		95.8	14,302 - 21,243	0.58 - 0.98	5,983 - 8,844	5, 6, 9
Natural gas-fired	LNB	NO_X	40	1,205 - 2,405	0.190 - 0.346	412 - 7,075	5, 7, 9
	LNB w/ OFA		40 - 60	1,722 - 3,435	NA	412 - 7,075	5, 7, 9
	LNB w/ OFA and FGR		40 - 80	2,690 - 5,368	NA	439 - 6,689	5, 7, 9
	SNCR		30 - 75	2,840 - 5,666	0.206 - 0.355	1,997 - 9,952	5, 7, 9
	SCR		70 - 90	5,399 - 10,773	0.484 - 0.831	1,022 - 24,944	5, 7, 9
Wood-fired	SNCR	NO_X	30 - 75	2,840 - 5,666	0.206 - 0.355	1,997 - 9,952	5, 7, 9
	SCR		40 - 90	5,399 - 10,773	0.484 - 0.831	1,022 - 24,944	5, 7, 9
	Fabric filter	$PM_{2.5}$, PM_{10}	95.8	17,205 - 26,291	0.72 - 1.20	7,298 - 10,889	5, 6, 9
	ESP		95.8	14,302 - 21,243	0.58 - 0.98	5,983 - 8,844	5, 6, 9

NA - Control cost not available.
Annual cost assumes 7.5% interest rate and 15-year project life.
Capital and annual costs are presented in 2007 dollars.

Table 6-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Industrial Boilers

Source Type	Control Technology	Pollutant controlled	Energy and non-air pollution impacts (per ton of emission reduced)				
			Electricity requirement	Steam requirement	Solid waste produced	Wastewater produced	Additional CO_2 emitted
Coal-fired	LNB	NO_X					
	LNB w/OFA	NO_X					
	SNCR	NO_X	1 - 2 kW/1000 acfm	0.25			
	SCR	NO_X	0.89	0.25	0.021		
	Physical coal cleaning	SO_2					
	Chemical coal cleaning	SO_2					
	Switch to lower sulfur fuel	SO_2					
	Dry sorbent injection	SO_2	2 - 4 kW/1000 acfm	0.25	0.021		
	Spray dryer absorber	SO_2	0.4		3.7	0.69	
	Wet FGD	SO_2	4 - 8 kW/1000 acfm				
	Fabric filter	$PM_{2.5}$, PM_{10}	1 - 2 kW/1000 acfm				
	ESP	$PM_{2.5}$, PM_{10}	0.5 - 1.5 kW/1000 acfm				
Oil-fired	LNB	NO_X					
	LNB w/ OFA	NO_X					
	LNB w/ OFA and FGR	NO_X	6.4				
	SNCR	NO_X	1 - 2 kW/1000 acfm	0.25			
	SCR	NO_X	0.89	0.25	0.021		
	Switch to lower sulfur fuel	SO_2					
	Spray dryer absorber	SO_2	0.4		3.7	0.69	
	Wet FGD	SO_2	4 - 8 kW/1000 acfm				
	Fabric filter	$PM_{2.5}$, PM_{10}	1 - 2 kW/1000 acfm				
	ESP	$PM_{2.5}$, PM_{10}	0.5 - 1.5 kW/1000 acfm				
Natural gas-fired	LNB	NO_X					
	LNB w/ OFA	NO_X					
	LNB w/ OFA and FGR	NO_X	6.4				
	SNCR	NO_X	1 - 2 kW/1000 acfm	0.25			
	SCR	NO_X	0.89	0.25	0.021		
	Water injection	NO_X					
Wood-fired	LNB w/ OFA	NO_X					
	LNB w/ OFA and FGR	NO_X	6.4				
	ULNB	NO_X					
	SNCR	NO_X	1 - 2 kW/1000 acfm	0.25			
	SCR	NO_X	0.89	0.25	0.021		
	Fabric filter	$PM_{2.5}$, PM_{10}	1 - 2 kW/1000 acfm				
	ESP	$PM_{2.5}$, PM_{10}	0.5 - 1.5 kW/1000 acfm				

NOTES:
A blank cell indicates no impact is expected.

For SO_2 control technologies, energy is required 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.

PM control technologies require energy to operate compressors, heaters, and ash handling. In addition, an additional fan may be required to reduce the flue gas pressure loss by the ESP or FF. The ESP also requires energy to operate the transformer-rectifier. These energy requirements will produce an increase in CO_2 emissions to generate the required electricity.

6.4 Factor 4 – Remaining Equipment Life

Similar to Electric Generating Units (EGUs), industrial boilers 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.

6.5 References for Section 6

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

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

7. Cement Kilns

The main emission units of interest at cement plants are the cement kilns. There are two major types, wet and dry kilns; dry kilns are further categorized as long dry, preheater, or precalciner kilns. On the whole, wet kilns tend to produce more tons of cement (or “clinker”) but also require more energy than dry process kilns. There was limited information on SO_2 controls for cement kilns, particularly for long wet kilns.[1] Process modification and replacement of a wet kiln with a dry process kiln are the most feasible options for SO_2 control.

Cement kilns at cement manufacturing facilities in the WRAP region are estimated to emit about 40,610 tons of NO_X; 6,230 tons of SO_2; 1,573 tons of $PM_{2.5}$; 4,245 tons of PM_{10} and 4,467 tons of VOC per year, based on the 2002 emissions inventory for the region and WRAP updates.[2] Most of the emissions from this category are from the kilns themselves; the remainder of the emissions is generated primarily from the transfer of clinker and the grinding and drying of the raw material. NO_X emissions from cement kilns represent approximately 4% of total point source emissions of NO_X in the WRAP region, and approximately 3% of all stationary source (point and area source) NO_X emissions in the region. SO_2 emissions from cement kilns represent approximately 0.75% of total point source emissions of SO_2 in the WRAP region, and approximately 0.68% of all stationary source (point and area source) SO_2 emissions in the region.

Table 7-1 shows estimated emissions of NO_X, SO_2, PM_{10}, $PM_{2.5}$ and VOC from the WRAP emissions inventory and updated data provided by the states, broken down by state and emission source. As the table shows, SO_2, PM_{10}, $PM_{2.5}$ and VOC emissions from cement kiln sources are much lower than NO_X emissions. Emissions of particulate matter from these sources were not included in the WRAP EDMS inventory – the emissions presented were gathered from the NEI. Long dry kilns produce over half of the NO_X emissions (54.8%) and most of the $PM_{2.5}$ and PM_{10} emissions (79.4 and 71.3%, respectively) generated by cement manufacturing in the WRAP region. Long wet kilns produce almost half of the SO_2 emissions generated by the cement manufacturing (48.4%), and precalciner kilns produce almost half of the VOC emissions generated by cement manufacturing (45.6%).

Table 7-2 lists potential control measures for NO_X emissions from cement kilns. A number of options were identified for cement kilns in an ACT guidance document written by the U.S. EPA in 1994.[6] Cement kilns use coal, waste products, tires, or natural gas for combustion fuel - this combustion generates primarily NO_X emissions but also produces SO_2 and PM emissions.[6] Controls can be broken into three categories: process modifications, combustion modifications and NO_X removal controls. Process modifications include fuel switching and the inclusion of steel slag into the raw kiln feed (also known as the CemStar$^{(TM)}$ process) which improves thermal efficiency. CemStar is currently used in TXI’s Hunter and Midlothian, TX plants, TXI’s Oro Grande, CA plant and Holcim’s North Texas Cementer plant. TXI has also licensed CemStar out to RMC Pacific Materials, Inc. and to the Rio Grande Portland Cement Company.[3] Combustion modifications include low NO_X burners and mid-kiln firing. NO_X removal controls include SCR, SNCR, LoTOX^{TM}, and biosolids or sorbent injection. Low NO_X

burners reduce flame turbulence, delay fuel/air mixing and create fuel-rich zones for initial combustion, reducing the flame temperature and thus NO_X formation.[4] SCR introduces ammonia, presented as a catalyst, into the clinker making process to selectively reduce NO_X emissions from exhaust gases. SNCR, available to preheater or precalciner cement kilns[1,5,6], does not use a catalyst to reduce NO_X emissions. Instead, the process uses either ammonia or urea that is generated when reagents are injected into the kiln at specific temperatures. However, SNCR has been tested primarily in European facilities; there have been two demonstrations in the United States but no kilns have yet adopted the technology.[7,8,9,10,11]

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.[12] LoTOx is licensed by the BOC group and is currently being used on the Midlothian cement wet kilns in Texas.[1,12] Biosolid or absorbent injection is similar to SNCR, although instead of a catalyst either biosolids from wastewater treatment plants or limestone/hydrated lime are injected into the kiln.[7,13] Biosolid injection is being used in one kiln in Southern California where dewatered sewage sludge is injected into the mixing chamber where the flue gas streams from the kiln and the precalciner mix together. [14,15]

7.1 Factor 1 – Costs

Table 7-3 provides cost estimates for the emission control options which have been identified for cement kilns. 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 and annual cost figures are expressed in terms of the cost per unit of clinker tonnage produced, or cubic feet per minute (cfm) for PM emission sources. The table shows a range of values for each cost figure since the cost per unit of clinker tonnage will depend on the amount of clinker produced and other factors. The lower ends of the cost ranges typically reflect smaller kilns and the higher ends of the cost ranges typically reflect larger kiln sizes. Table 7-3 also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

7.2 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 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] Additional time of up to 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 cement kilns is estimated at a total of 5½ years.

Table 7-1. Emissions from Cement Kilns in the WRAP Region

Emission Source	AK	AZ	CA	CO	ID	MT	ND	NM	NV	OR	SD	UT	WA	WY	Tribes	All
NO_X emissions (tons/year)																
Wet Process Kiln	0	0	0	1136	461	1814	0	0	0	0	2966	0	2251	0	0	8,628
Dry Process Kiln	0	2476	11544	2162	0	0	0	804	0	1741	0	0.012	1213	2080	0	22,020
Clinker Transfer	0	0	601	0	0	0	0	0	0	0	0	0	0	0	0	601
Raw Material Grinding and Drying	0	0	78	12	0	0	0	0	0	0	0	0	0	0	0	91
Preheater/Precalciner Kiln	0	5066	1370	511	0	0	0	0	0	0	0	1322	0	0	0	8,269
Other	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	5
Total	0	7,542	13,598	3,821	461	1,814	0	804	0	1,741	2,966	1,322	3,464	2,080	0	39,613
SO_2 emissions (tons/year)																
Wet Process Kiln	0	0	0	240	17	233	0	0	0	0	656	0	771	0	0	1,917
Dry Process Kiln	0	61	2101	18	0	0	0	15	0	38	0	0.001	188	207	0	2,628
Clinker Transfer	0	0	86	0	0	0	0	0	0	0	0	0	0	0	0	86
Raw Material Grinding and Drying	0	0	11	32	0	0	0	0	0	0	0	0	0	0	0	43
Preheater/Precalciner Kiln	0	9	1	378	0	0	0	0	0	0	0	58	0	0	0	446
Other	0	0	0.44	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	70	2,200	667	17	233	0	15	0	38	656	58	959	207	0	5,121
$PM_{2.5}$ emissions (tons/year)																
Wet Process Kiln	0	0	14	0	3	0	0	0	0	0	91	6	6	0	0	121
Dry Process Kiln	0	0	1184	0	0	0	0	3	0	0	0	32	28	0	0	1,247
Clinker Transfer	0	0.48	105	3	0.47	0	0	0	0	0	0	1	0	0	0	110
Raw Material Grinding and Drying	0	0.26	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Preheater/Precalciner Kiln	0	74	2	15	0	0	0	0	0	0	0	5	0	0	0	95
Other	0	0	0	0	0.24	0	0	0	0	0	0	0	0	0	0	0.24
Total	0	75	1,305	18	4	0	0	3	0	0	91	44	34	0	0	1,573

Table 7-1. Emissions from Cement Kilns in the WRAP Region

Emission Source	AK	AZ	CA	CO	ID	MT	ND	NM	NV	OR	SD	UT	WA	WY	Tribes	All
PM_{10} emissions (tons/year)																
Wet Process Kiln	0	0	20	75	4	376	0	0	0	0	185	17	14	0	0	691
Dry Process Kiln	0	0	2023	414	0	1	0	97	0	64	0	222	30	179	0	3,030
Clinker Transfer	0	1	163	5	2	0	0	0	0	0	0	4	0	0	0	175
Raw Material Grinding and Drying	0	0.47	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Preheater/Precalciner Kiln	0	132	5	26	0	0	0	0	0	0	0	14	0	0	0	178
Other	0	0	0	0	0.84	0	0	0	0	0	0	0	0	0	0	1
Total	0	134	2,211	521	7	377	0	97	0	64	185	257	44	179	0	4,075
VOC emissions (tons/year)																
Wet Process Kiln	0	0	0	0	1	0	0	0	0	0	81	0	0	0	1	84
Dry Process Kiln	0	10	114	3	0	0	0	33	0	15	0	1	0	46	0	221
Clinker Transfer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Raw Material Grinding and Drying	0	1	0	125	0	0	0	0	0	0	0	0	0	0	0	126
Preheater/Precalciner Kiln	0	5	4	2	0	0	0	0	0	0	0	42	0	0	1,984	2,038
Other	0	6	1	0	0	0	0	2	0	0	4	0	0	0	1,986	1,999
Total	0	21	119	131	1	0	0	35	0	15	85	43	0	46	3,972	4,467

Table 7-2. Control Options for Cement Kilns

Source Type	Control Technology	Pollutant controlled	Baseline emissions	Estimated control efficiency (%)	Potential emission reduction (tons/year)	References
Long Wet Kiln	Low NOX burners	NO_X	8,628	20-30	1725 - 2588	1, 6
	Mid-kiln firing	NO_X	8,628	20-50	1725 - 4313	1, 6
	SCR with ammonia	NO_X	8,628	80-90	6902 - 7764	5, 6
	SNCR with ammonia or urea	NO_X	8,628	30-70	2588 - 6039	6
	Biosolid injection	NO_X	8,628	50	4313	7
	CemStar^{TM} process	NO_X	8,628	20-60	1725 - 5176	1, 3, 7
	LoTOx^{TM}	NO_X	8,628	80-90	6902 - 7765	1, 5
	Dry ESP	PM_{10}	691	95-98	656 - 677	9
	Dry ESP	$PM_{2.5}$	121	95-98	114 - 118	9
	Dry ESP	EC	4	95-98	3	9
	Dry ESP	OC	15	95-98	14	9
	Fabric Filter	PM_{10}	691	80-99	656 - 677	9
	Fabric Filter	$PM_{2.5}$	121	80-99	114 - 118	9
	Fabric Filter	EC	4	80-99	3	9
	Fabric Filter	OC	15	80-99	14	9
	Absorbant Addition	SO_2	1,917	60-80	1150 - 1533	
	Wet FGD	SO_2	1,917	90-99	1725 - 1897	1
Long Dry Kiln	Low NOX burners	NOX	19541	40	7816	1, 6
	Mid-kiln firing	NOX	19541	11-55	2149 - 10747	1, 6
	SCR with ammonia	NOX	19541	80-90	1563 - 1758	6
	Biosolid injection	NOX	19541	50	9770	7
	LoTOx^{TM}	NO_X	19541	80 - 90	15,633 - 17,587	1, 5
	CemStar^{TM} process	NOX	19541	20-60	3908 - 1172	1, 3, 7
	Dry ESP	PM10	3,030	95-98	2878 - 2969	9
	Dry ESP	PM2.5	1,247	95-98	1184 - 1221	9
	Dry ESP	EC	37	95-98	34 - 36	9
	Dry ESP	OC	158	95-98	150 - 155	9
	Fabric Filter	PM10	3,030	99	3000	9
	Fabric Filter	PM2.5	1,247	99	1234	9
	Fabric Filter	EC	37	99	36	9
	Fabric Filter	OC	158	99	156	9
	Wet FGD	SO2	2567	90-99	2310 - 2541	1
	Dry FGD	SO2	2567	90-95	2310 - 2438	1
	Sorbent injection	SO2	2567	60-80	1540 - 2053	

Table 7-2. Control Options for Cement Kilns

Source Type	Control Technology	Pollutant controlled	Baseline emissions	Estimated control efficiency (%)	Potential emission reduction (tons/year)	References
Preheater Kiln	Low NOX burners	NOX	3204	40	1281	1, 6
	Mid-kiln firing	NOX	3204	11-55	352 - 1762	1, 6
	SCR with ammonia	NOX	3204	85	2723	5, 6
	SNCR with urea	NOX	3204	35	1121	5, 6
	SNCR with ammonia	NOX	3204	35	1121	5, 6
	LoTOx™	NO_X	3204	80 - 90	2,563 - 2,884	1, 5
	CemStar™ process	NOX	19541	Unknown[a]	Unknown[a]	1, 3, 7
	Biosolid injection	NOX	3204	23 - 50	736 - 1602	7, 9
	Dry ESP	PM10	178	95-98	169 - 174	9
	Dry ESP	PM2.5	95	95-98	90 - 93	9
	Dry ESP	EC	3	95-98	2	9
	Dry ESP	OC	12	95-98	11 - 11	9
	Fabric Filter	PM10	178	99	176	9
	Fabric Filter	PM2.5	95	99	94	9
	Fabric Filter	EC	3	99	2	9
	Fabric Filter	OC	12	99	11	9
	Wet FGD	SO2	436	90-99	392 - 431	1
	Dry FGD	SO2	436	90-95	392 - 414	1
	Sorbent injection	SO2	436	60-80	261 - 348	8
Precalciner Kiln	Low NOX burners	NOX	3204	30-40	961 - 1281	6
	Mid-kiln firing	NOX	3204	11-55	352 - 1762	1, 6
	SCR with ammonia	NOX	3204	85	2723	5, 6
	SNCR with urea	NOX	3204	35	1121	5, 6
	SNCR with ammonia	NOX	3204	35	1121	5, 6
	LoTOx™	NO_X	3204	80 - 90	2,563 - 2,884	1, 5
	CemStar™ process	NOX	19541	Unknown[a]	Unknown[a]	1, 3, 7
	Biosolid injection	NOX	3204	50	1602	7
	Dry ESP	PM10	178	95-98	169 - 174	9
	Dry ESP	PM2.5	95	95-98	90. - 93.	9
	Dry ESP	EC	3	95-98	2.6 - 2.7	9
	Dry ESP	OC	12	95-98	11 - 11	9
	Fabric Filter	PM10	178	99	176	9
	Fabric Filter	PM2.5	95	99	94	9
	Fabric Filter	EC	3	99	2	9
	Fabric Filter	OC	12	99	11	9
	Wet FGD	SO2	436	90-99	392 - 431	1
	Dry FGD	SO2	436	90-95	392 - 414	1
	Sorbent injection	SO2	436	60-80	261 - 348	8

a The CemStar process has been analyzed for long wet and dry kilns only although the process is currently being used in long dry kilns and preheater/precalciner kilns at two facilities, one in Texas and one in California. It is unknown what the control efficiency is of the CemStar process in preheater or precalciner kilns.

7.3 Factor 3 – Energy and Other Impacts

Table 7-4 shows the estimated energy and non-air pollution impacts of control measures for cement kilns. In general in-combustion NO_X control technologies will increase energy efficiency of the cement production process since these technologies reduce excess air and burning.[18] SCR requires additional energy input since the process required a particular gas temperature, requiring the gas stream to be reheated. An additional 9.8 percent of the total energy required in cement manufacturing will be needed to utilize the SCR control technology.[18] In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal.[19]

7.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of cement kilns in the WRAP region. Cement kilns have no set equipment life. The units, whether wet or dry, can be refurbished to extend their lives. In addition, it is assumed that controls will be not be applied to units that are expected to be retired prior to the amortization period for the control equipment. Therefore, remaining equipment life is not expected to affect the cost of control for cement kilns.

Table 7-3. Estimated Costs of Control for Cement Kilns

Source Type	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Estimated capital cost ($1000/unit)	Estimated annual cost ($/year/unit)	Units	Cost effectiveness ($/ton)	References
Long Wet Kiln	Low NOX burners (indirect fired)	NOX	20-47	401 - 564	100,000 - 144,000	ton clinker	270 - 620	1, 6, 7
	Low NOX burners (direct fired)	NOX	20-47	1,910	376,000 - 343,500	ton clinker	855 - 1,005	1, 6, 7
	Mid-kiln firing	NOX	20-50	613 - 3,205	183,500 - (192,300	ton clinker	(460) - 730	1, 6, 7, 8
	SCR with ammonia	NOX	80-90	15,100	5,780 - 4,105,000	ton clinker	3,370	5, 6, 7
	LoTOx™	NOX	80 - 90	Not available[a]			3,155 - 3,891[c]	5
	CemStar™ process	NOX	20-60	1,176	220000	ton clinker	550	7
	Dry ESP	PM_{10}, $PM_{2.5}$, OC, EC	95-98	Not available[a]			40 - 250	9
	Fabric Filter	PM_{10}, $PM_{2.5}$, OC, EC	80-99	Not available[a]			117 - 148	9
	Wet FGD	SO2	90-99	Not available[a]			2,211 - 6,917	1, 8
Long Dry Kilns	Low NOX burners (indirect fired)	NOX	30 - 40	334 - 509	83,000 - 135,500	ton clinker	300 (3) - 620	1, 6, 7
	Low NOX burners (direct fired)	NOX	40	1,455	298,000 - 272,500	ton clinker	166 - 1,299	1, 6, 7
	Mid-kiln firing	NOX	11-55	455 - 3,180	89,830 - 144,000	ton clinker	(460) - 730	1, 6, 7, 8
	LoTOx™	NOX	80 - 90	Not available[d]				5
	CemStar™ process	NOX	20-60		Not available[b]			7
	SCR with ammonia	NOX	80-90	11,485	3,000,000	ton clinker	586 - 3,400	6, 7, 8
	Dry ESP	PM_{10}, $PM_{2.5}$, OC, EC	95-98	Not available[a]			40 - 250	9
	Fabric Filter	PM_{10}, $PM_{2.5}$, OC, EC	80-99	Not available[a]			117 - 148	9
	Wet FGD	SO2	90-99	5,610 - 84,000	10,000 - 30,571	ton clinker	2,000 - 4,000	1, 8
	Dry FGD	SO2	90-95	3,300 - 95,800	9,142 - 32,286	ton clinker	1,900 - 7,000	1
Preheater Kilns	Low NOX burners (indirect fired)	NOX	30 - 40	379 - 608	94,500 - 150,000	ton clinker	300 - 620	1, 6, 7
	Low NOX burners (direct fired)	NOX	40	1,765 - 1,800	351,500 - 330,000	ton clinker	175 - 1,201	1, 6, 7
	CemStar™ process	NOX	20-60		Not available[b]			
	SCR with ammonia	NOX	85	14,400	3,850,000	ton clinker	500 - 3,805	5, 6, 7, 8
	SNCR with urea	NOX	35	799	546500	ton clinker	(310) - 2,500	5, 6, 8
	SNCR with ammonia	NOX	35	1,595	635500	ton clinker	(310) - 2,500	5, 6, 8
	LoTOx™	NOX	80 - 90	Not available[d]				5
	Biosolids Injection	NOX	50	1,200	(322,000)	ton clinker	(310)	7
	Dry ESP	PM_{10}, $PM_{2.5}$, OC, EC	95-98	0.013	Not available[a]	cfm	40 - 250	9
	Fabric Filter	PM_{10}, $PM_{2.5}$, OC, EC	99	0.029	Not available[a]	cfm	117 - 148	9
	Wet FGD	SO2	90-99	3,710 - 54,000	2,714 - 15,857	ton clinker	2,000 - 64,600	1, 8
	Dry FGD	SO2	90-95	2,100 - 61,400	2,857 - 17,571	ton clinker	10,000 - 72,800	1
	Sorbent Injection	SO2	60 - 80	Not available[a]			2,031 - 7,379	8

Table 7-3. Estimated Costs of Control for Cement Kilns

Source Type	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Estimated capital cost ($1000/unit)	Estimated annual cost ($/year/unit)	Units	Cost effectiveness ($/ton)	References
Precalciner Kilns	Low NOX burners (indirect fired)	NOX	30	406 - 863	101,000 - 188,500	ton clinker	245 - 620	6, 7
	Low NOX burners (direct fired)	NOX	30	1,945 - 2,235	382,500 - 393,500	ton clinker	920 - 985	6, 7
	CemStar™ process	NOX	20-60	Not available[b]				
	LoTOx™	NOX	80 - 90	Not available[a]			2,419 - 2,734[e]	5
	SCR with ammonia	NOX	85	21,950	6,240,000	ton clinker	4635	5, 6, 7
	SNCR with urea	NOX	35	1,105	709,000	ton clinker	(310) - 2,500	5, 6, 8
	SNCR with ammonia	NOX	35	1,880	779,500	ton clinker	(310) - 2,500	5, 6, 8
	Biosolids Injection	NOX	23 - 50	5,581	1,498	ton clinker	(310)	7, 8
	Dry ESP	PM_{10}, $PM_{2.5}$, OC, EC	99	0.013	Not available[a]	cfm	40 - 250	9
	Fabric Filter	PM_{10}, $PM_{2.5}$, OC, EC	99	0.029	Not available[a]	cfm	117 - 148	9
	Sorbent Injection	SO2	60-80	Not available[a]			2,031 - 7,379	8
	Wet FGD	SO2	90-99	3,710 - 54,000	2,714 - 15,857	ton clinker	2,211 - 6,917	8

a References discussing this particular control technology did not provide any capital or annual costs but only a cost effectiveness figure.

b The CemStar process has been costed for long wet kilns only although the process is currently being used in long dry kilns and preheater/precalciner kilns at two facilities, one in Texas and one in California.

c The cost effectivenes was calculated for a wet kiln that did not already have a scrubber system in place.

d 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).

e The cost effectiveness was calculated for a precalciner kiln that already has a scrubber system in place.

Table 7-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Cement Kilns

					Energy and non-air pollution impacts				
Source Type	Control Technology	Pollutant controlled	Potential emission reduction (tons/year)	Additional Fuel Requirement (%)	Additional electricity requirement (kW/ton reduced)	Steam requirement (tons steam/ton reduced)	Solid waste produced (tons waste/ton reduced)	Wastewater produced (million gallons/ton reduced)	Additional CO_2 emitted (tons/ton reduced)
Long Wet Kilns	Low NOX burners	NO_X	1725 - 2588	a	182				
	Mid-kiln firing	NO_X	1725 - 4313	a	182				
	SCR with ammonia	NO_X	6902 - 7764	9.8	57				Unknown[b]
	SNCR with ammonia or urea	NO_X	2588 - 6039		Unknown[b]				
	Biosolid injection	NO_X	4313	a					
	LoTOx™	NO_X	6902 - 7765		Unknown[c]				
	CemStar™ process	NO_X	1725 - 5176	a					
	Fabric Filter	PM_{10}, $PM_{2.5}$, EC, OC	1,898 - 1,958		Unknown[b]		1		
	Dry ESP	PM_{10}, $PM_{2.5}$, EC, OC	1,898 - 1,958		Unknown[b]		1		
	Wet FGD	SO_2	1725 - 1897		1,100	3.1	2.8	3.7	2.6
Long Dry Kilns	Low NOX burners	NO_X	7816	a	158				
	Mid-kiln firing	NO_X	2149 - 10747	a	158				
	SCR with ammonia	NO_X	1563 - 1758	9.8	48				Unknown[b]
	Biosolid injection	NO_X	9770						
	LoTOx™	NO_X	15,633 - 17,587		Unknown[c]				
	CemStar™ process	NO_X	3908 - 1172						
	Dry ESP	PM_{10}, $PM_{2.5}$, EC, OC	1,898 - 1,958		Unknown[b]		1		
	Fabric Filter	PM_{10}, $PM_{2.5}$, EC, OC	1,898 - 1,958		Unknown[b]		1		
	Wet FGD	SO_2	2310 - 2541		1,100	3.1	2.8	3.7	2.6
	Dry FGD	SO_2	2310 - 2438		Unknown[b]				

Table 7-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Cement Kilns

					Energy and non-air pollution impacts				
Source Type	Control Technology	Pollutant controlled	Potential emission reduction (tons/year)	Additional Fuel Requirement (%)	Additional electricity requirement (kW/ton reduced)	Steam requirement (tons steam/ton reduced)	Solid waste produced (tons waste/ton reduced)	Wastewater produced (million gallons/ton reduced)	Additional CO_2 emitted (tons/ton reduced)
Preheater Kilns	Low NOX burners	NO_X	1281	a	194				
	SCR with ammonia	NO_X	2723	9.8	59				Unknown[b]
	SNCR with urea	NO_X	1121		Unknown[b]				
	SNCR with ammonia	NO_X	1121		Unknown[b]				
	LoTOx[TM]	NO_X	2,563 - 2,884		Unknown[c]				
	Biosolid injection	NO_X	736 - 1602	a					
	Sorbent injection	SO_2	261 - 348	a					
	Dry ESP	PM_{10}, $PM_{2.5}$, EC, OC	1,898 - 1,958		Unknown[b]		1		
	Fabric Filter	PM_{10}, $PM_{2.5}$, EC, OC	1,898 - 1,958		Unknown[b]		1		
	Wet FGD	SO_2	392 - 431		1,100	3.1	2.8	3.7	2.6
	Dry FGD	SO_2	392 - 414		Unknown[b]				
Precalciner Kilns	Low NOX burners	NO_X	961 - 1281	a	285				
	SCR with ammonia	NO_X	2723	9.8	89				Unknown[b]
	SNCR with urea	NO_X	1121		Unknown[b]				
	SNCR with ammonia	NO_X	1121		Unknown[b]				
	LoTOx[TM]	NO_X	2,563 - 2,884		Unknown[c]				
	Biosolid injection	NO_X	1602	a					
	Sorbent injection	SO_2	60-80	a					
	Dry ESP	PM_{10}, $PM_{2.5}$, EC, OC	1,898 - 1,958		Unknown[b]		1		
	Fabric Filter	PM_{10}, $PM_{2.5}$, EC, OC	1,898 - 1,958		Unknown[b]		1		
	Wet FGD	SO_2	392 - 431		1,100	3.1	2.8	3.7	2.6
	Dry FGD	SO_2	392 - 414		Unknown[b]				

a - The measure is expected to improve fuel efficiency.

b - Impacts are expected, however there is no available information to quantify these impacts.

c - According to the ERG Report (reference 3) "electricity and oxygen costs are reported to be high" although there is no quantification given.

7.5 References for Section 7

1. 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.

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

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

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17. Ghoreishi, Farrokh (2007), Personal communication, *Time required to install add-on control measures for NO_X*, Wisconsin Department of Natural Resources, April 27.

18. Reference 3, Chapter 7.

19. 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, http://www.epa.gov/ttncatc1/products.html#cccinfo.

8. Sulfuric Acid Manufacturing Plants

Sulfuric acid manufacturing plants account for about 4,700 tons/year of SO_2 emissions in the WRAP region. These emissions are from a limited number of facilities, with facility-level SO_2 emissions ranging from about 100 tons/year to about 2,000 tons/year. Table 8-1 summarizes emissions from the sulfuric acid manufacturing plants, broken down by state, based on the WRAP emissions inventory and the NEI.[1] The table also shows the amounts of SO_2 emissions from facilities at different efficiency levels for the acid recovery process. As the table shows, reported emissions of NO_X, PM_{10}, $PM_{2.5}$, and VOC emissions are much lower than SO_2 emissions from sulfuric acid plants in the region.

Emissions of SO_2 from sulfuric acid manufacturing processes can be reduced by increasing the absorption efficiency of the acid recovery process. The NSPS emission level for sulfuric acid plants corresponds to an estimated recovery efficiency of 99.75%.[2] Based on the SCC used in the WRAP inventory, the recovery efficiency ranges from 93 to 99% for most of the emission sources in the WRAP region. Increasing the efficiency of sulfuric acid plants to the NSPS level would result in emission reductions 75 to 96.4% from the current baseline level of control. This increase in efficiency is achieved by adding more absorption stages to the acid recovery process. SO_2 emissions can also be controlled using tail gas treatment units.[3,4] Table 8-2 shows the estimated control efficiencies and emission reductions which could be achieved for sulfuric acid plants operating at different baseline levels of control.

8.1 Factor 1 – Costs

Table 8-3 provides cost estimates for the emission control options which have been identified for sulfuric acid manufacturing plants. 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 and annual cost figures are expressed in terms of the cost per unit of gas treated, in actual cubic feet per minute (acfm).

Table 8-3 shows a range of values for each cost figure, since the cost per unit of throughput will depend on the process size and other factors. The lower ends of the cost ranges typically reflect larger processes, and the higher ends of the cost ranges typically reflect lower process sizes. The table also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

Table 8-1. Emissions from Sulfuric Acid Manufacturing Plants in the WRAP Region

	CA	ID	WA	WY	Tribes	All
			NO_X emissions (tons/year)			
General	32	0	10	54	7	103
			SO_2 emissions (tons/year)			
Contact process						
99% efficient	710					710
98% efficient			105			105
93% efficient		364				364
Unspecified				2,012	897	2,909
Chamber process	600					600
Total	1,310	364	105	2,012	897	4,688
			VOC emissions (tons/year)			
General	2			23	2	27

Table 8-2. Control Options for Sulfuric Acid Manufacturing Plants

Source Type	Control Technology	Pollutant controlled	Baseline emissions	Estimated control efficiency (%)	Potential emission reduction (tons/year)	Refer-ences
Contact process						
99% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	710	75	530	2,3
	Tailgas treatment unit	SO_2	710	90	640	3,4
98% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	105	87.5	92	2,3
	Tailgas treatment unit	SO_2	105	95	100	3,4
93% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	3,273	96.4	3,200	2,3
	Tailgas treatment unit	SO_2	3,273	98.6	3,200	3,4
Chamber process	Tailgas treatment unit	SO_2	600	98.6	590	3,4

Table 8-3. Estimated Costs of Control for Sulfuric Acid Manufacturing Plants

Source Type	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Estimated capital cost ($/unit)	Estimated annual cost ($/year/unit)	Units	Cost effectiveness ($/ton)	Refer-ences
Contact process								
99% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	75	55 - 96	23 - 29	acfm	6,800 - 7,000	2,3
	Tailgas treatment unit	SO_2	90	23 - 32	36	acfm	5,300 - 6,500	3,4
98% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	87.5				6,200	2,3
	Tailgas treatment unit	SO_2	95	48	38	acfm	3,375	3,4
93% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	96.4				1,600	2,3
	Tailgas treatment unit	SO_2	98.6	48	38	acfm	928	3,4
Chamber process	Tailgas treatment unit	SO_2	98.6	19	34	acfm	8,100	3,4

8.2 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. In the CAIR analysis, EPA estimated that approximately 30 months is required to design, build, and install SO_2 scrubbing technology for a single emission source.[5] 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 achieve emission reductions for sulfuric acid manufacturing facilities is estimated at a total of 6½ years.

8.3 Factor 3 – Energy and Other Impacts

Table 8-4 shows the estimated energy and non-air pollution impacts of control measures for sulphuric acid plants. Additional absorption stages to increase acid plant efficiency would require additional electricity and steam,[2] as would a tailgas treatment unit.[4] This would result in increased CO_2 emissions to generate the electricity and steam.

8.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of sulfuric acid plants in the WRAP region. However, industrial processes often refurbished 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 this category. In the case of add-on technologies, the projected lifetime is 15 years.

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 8-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Sulfuric Acid Manufacturing Plants

				Energy and non-air pollution impacts (per ton of pollutant reduced)			
Source Type	**Control Technology**	**Pollutant controlled**	**Potential emission reduction (tons/year)**	**Additional electricity requirement (kW-hr)**	**Steam requirement (tons steam)**	**Solid waste produced (tons waste)**	**Additional CO_2 emitted (tons)**
Contact process							
99% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	530	2,450	29	<0.01	10
	Tailgas treatment unit	SO_2	640	1,470	27		8
98% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	92	1,050	13	<0.01	4
	Tailgas treatment unit	SO_2	100	700	12		4
93% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	3,200	270	3.2	<0.01	1
	Tailgas treatment unit	SO_2	3,200	190	3.5		1
Chamber process	Tailgas treatment unit	SO_2	590	2,450	29	<0.01	10

8.5 References for Section 8

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

2. EPA (1985), *Sulfuric Acid: Review of New Source Performance Standards for Sulfuric Acid Plants*, EPA/450/3-85/012, U.S. EPA, RTP, NC, http://nepis.epa.gov/.

3. E.H. Pechan & Associates (2005), *AirControlNET, Version 4.1 - Documentation Report*, U.S. EPA, RTP, NC, pp III-1223 through III-1276, http://www.epa.gov/ttnecas1/AirControlNET.htm.

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9. Pulp and Paper Lime Kilns

The pulp making process produces the largest amount of emissions in the pulp and paper industry, accounting for more than 75% of the sector's $PM_{2.5}$, SO_2, and NO_X emissions.[1] The role of lime kilns in the kraft pulping process is to produce white liquor and calcium carbonate.[2]

Lime kilns at pulp and paper manufacturing facilities in the WRAP region are estimated to emit about 828 tons of NO_X, 104 tons of SO_2, 603 tons of $PM_{2.5}$, 667 tons of PM_{10}, and 32 tons of VOC per year, based on the 2002 emissions inventory for the region.[3] The area source emissions estimates are derived from industrial, commercial, and institutional fuel consumption in the WRAP states. NO_X emissions from lime kilns represent approximately 0.08% of total point source emissions of NO_X in the WRAP region, and approximately 0.06% of all stationary source (point and area source) NO_X emissions in the region. SO_2 emissions from lime kilns represent approximately 0.01% of total point source emissions of SO_2 in the WRAP region, and approximately 0.01% of all stationary source (point and area source) SO_2 emissions in the region.

Table 9-1 shows estimated emissions of NO_X, SO_2, PM_{10}, $PM_{2.5}$ and VOC from the WRAP emissions inventory and updated data provided by the states, broken down by state and emission source. As the table shows, SO_2, PM_{10}, $PM_{2.5}$ and VOC emissions from lime kiln sources are much lower than NO_X emissions. PM emissions from these sources were not included in the WRAP EDMS inventory – the emissions presented were gathered from the 2002NEI.

Table 9-2 lists potential control measures for NO_X, SO_2, PM_{10} and $PM_{2.5}$ emissions from lime kilns. A number of options were identified for lime kilns in the AirControlNet documentation report written by Pechan in 2006.[4] Many of the controls listed are similar to those to control emissions from cement kilns (please see chapter 7). SCR and SNCR have been investigated as possible control technologies but have been found to be technically infeasible. Additionally, according to the NACAA, there are no technically feasible methods for controlling NO_X emissions from lime kilns.[1] Therefore NACAA discusses control options for PM emissions only.

9.1 Factor 1 – Costs

Table 9-3 provides cost estimates for the emission control options which have been identified for lime kilns used in the pulp and paper industry. 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 and annual cost figures are expressed in terms of the cost per standard cubic feet per minute (scfm). The table shows a range of values for each cost figure, since the cost per scfm will depend on the

Table 9-1. Emissions from Lime Kilns in the WRAP Region

	AK	CA	CO	ID	MT	ND	NM	NV	OR	UT	WA	WY	Tribes	All
							NO_X emissions (tons/year)							
Total*	0	66	0	99	236	0	0	0	96	0	308	23	0	828
							SO_2 emissions (tons/year)							
Total*	0	1	0	3.3	2	0	0	0	57	0	40	0	0	104
							$PM_{2.5}$ emissions (tons/year)							
Total*	0	40	0	87	31	0	0	0	336	0	109	0	0	603
							PM_{10} emissions (tons/year)							
Total*	0	53	0	93	38	0	0	0	370	0	113	0	0	667
							VOC emissions (tons/year)							
Total*	0	0.28	0	5	20	0	0	0	2.18	0	4	0	0	32

* The majority of emissions produced in the pulp and paper lime kiln operations are generated from the kilns themselves. Thus the total emissions presented in this table are emissions from kilns.

Table 9-2. Control Options for Lime Kilns

Source Type	Control Technology	Pollutant controlled	Baseline emissions	Estimated control effieiency (%)	Potential emission reduction (tons/year)	References
Kiln	Low NOX burners	NO_X	828	30	248	4
	Mid-kiln firing	NO_X	828	30	248	4
	LoTOX	NO_X	828			
	SCR with ammonia	NO_X	828	60 - 80	496 - 662	4
	SNCR with ammonia or urea	NO_X	828	50	414	4
	Wet FGD	SO_2	104	50	51	4
	Dry ESP	PM_{10}	1271	95-98	1207 - 1245	4
	Dry ESP	$PM_{2.5}$	1271	95-98	1207 - 1245	4
	Dry ESP	EC	37	95-98	35 - 36	4
	Dry ESP	OC	161	95-98	153 - 158	4

kiln size and other factors. The lower ends of the cost ranges typically reflect smaller kilns, and the higher ends of the cost ranges typically reflect larger kilns. Table 9-3 also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

9.2 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 ICAC has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control.[5] However, state regulators' experience indicates that closer to 18 months is required to install this technology.[6] Additional time of up to 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 pulp and paper lime kilns is estimated at a total of 5½ years.

9.3 Factor 3 – Energy and Other Impacts

Table 9-4 shows the estimated energy and non-air pollution impacts of control measures for pulp and paper lime kilns. Low NO_X burners negatively affect efficiency and energy usage,[7] and staged combustion, while lowering NO_X emissions, can lead to increased SO_2 emissions. SCR and SNCR require, on average, 890 kilowatt-hour (kWh) of electricity per ton of pollutant reduced, and 0.25 tons of steam for every ton of pollutant reduced. Approximately one ton of CO_2 is produced per mWh of electricity generated.[8] In addition, spent catalyst from the SCR technology would have to be changed periodically, producing an increase in solid waste disposal.[9] Installation of SCR would also require an increase in fuel consumption, which would also produce an increase in CO_2 emissions to generate the electricity.

Fabric filters and ESP technologies, on average, generate approximately one ton of solid waste for every ton of pollutant reduced. It is also likely that there will be additional electricity usage for in-combustion and post-combustion technologies.

9.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of reciprocating engines and turbines in the WRAP region. However, lime kilns, like cement kilns, have no set equipment life. These units can be refurbished to extend their lives. In addition, it is assumed that controls will be not be applied to lime kilns that are expected to be retired prior to the amortization period for the control equipment. Therefore, remaining equipment life is not expected to affect the cost of control for lime kilns.

Table 9-3. Estimated Costs of Control for Lime Kilns

Source Type	Control Technology	Pollutant controlled	Estimated control effieiency (%)	Estimated capital cost ($1000/unit)	Estimated annual cost ($/year/unit)	Units	Cost effectiveness ($/ton)	References
Kilns	Low NO_X burners	NO_X	30		Not available		560	4
	Mid-kiln firing	NO_X	30		Not available		460	4
	SCR with ammonia	NO_X	60 - 80		Not available		3370	4
	SNCR with ammonia or urea	NO_X	50		Not available		770 - 850	4
	Wet FGD	SO_2	50		Not available			4
	Dry ESP	$PM_{2.5}$	95	15 - 50	4 - 40	scfm		4
	Dry ESP	PM_{10}	98	15 - 50	4 - 40	scfm	40-250	4
	Dry ESP	EC	95	15 - 50	4 - 40	scfm		4
	Dry ESP	OC	95	15 - 50	4 - 40	scfm		4
	Wet ESP	$PM_{2.5}$	95		Not available			4
	Wet ESP	PM_{10}	99	30 - 60	6 - 45	scfm	55 - 550	4
	Wet ESP	EC	95		Not available			4
	Wet ESP	OC	95		Not available			4

Table 9-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Lime Kilns

			Energy and non-air pollution impacts						
Source Type	**Control Technology**	**Pollutant controlled**	**Potential emission reduction (tons/year)**	**Additional Fuel Requirement (%)**	**Additional electricity requirement (kW-hr/ton reduced)**	**Steam requirement (tons steam/ton reduced)**	**Solid waste produced (tons waste/ton reduced)**	**Wastewater produced (million gallons/ton reduced)**	**Additional CO_2 emitted (tons/ton reduced)**
Kilns	Low NOX burners	NO_X	30	Unknown	Unknown				
	Mid-kiln firing	NO_X	30		a				
	SCR with ammonia	NO_X	60 - 80	Unknown	890	0.25			1
	SNCR with ammonia or urea	NO_X	50	Unknown	890	0.25			1
	Wet FGD	SO2	90		1,100	3.1	2.8	3.7	2.6
	Dry ESP	PM10, PM2.5, EC, OC	95-98		Unknown		1		
	Fabric Filter	PM10, PM2.5, EC, OC	95-99		Unknown		1		

a - The measure is expected to improve fuel efficiency.

9.5 References for Section 9

1. 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, Chapter 8, http://www.4cleanair.org/PM25Menu-Final.pdf.

2. Davis, W. (2000), *Air Pollution Engineering Manual: Second Edition*, Air & Waste Management Association.

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

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

5. Institute of Clean Air Companies (2006), *Typical Installation Timelines for NO_X Emissions Control Technologies on Industrial Sources*, http://www.icac.com/files/public/ICAC_NOx_Control_Installation_Timing_120406.pdf.

6. Ghoreishi, Farrokh (2007), Personal communication, *Time required to install add-on control measures for NO_X*, Wisconsin Department of Natural Resource, April 27.

7. Northeast States for Coordinated Air Use Management (NESCAUM) (2005), *Assessment of BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities*, http://bronze.nescaum.org/committees/haze/BART_Control_Assessment.pdf.

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9. 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, http://www.epa.gov/ttncatc1/products.html#cccinfo.

10. Oil Refineries

Petroleum refineries in the WRAP region are estimated to emit about 25,000 tons of NO_X and 58,000 tons of SO_2, based on the WRAP emissions inventory. These emissions represent about 2% of stationary source (point and area source) NO_X emissions, and 6% of stationary source SO_2 emissions in the region. PM_{10} and $PM_{2.5}$ emissions from natural gas processing facilities are estimated to be an order of magnitude lower than NO_X and SO_2 emissions.

Table 10-1 summarizes estimated emissions from petroleum refineries in the WRAP region, broken down by state and by the various emission sources. These emissions estimates are based on the 2002 WRAP emissions inventory.[1] Major sources of NO_X and SO_2 emissions at refineries in the WRAP region include process heaters, catalytic cracking units, coking units and ancillary operations, flares and incinerators. Other sources include boilers, which have been discussed in Chapter 6, and reciprocating engines and turbines, which have been discussed in Chapter 3.

Emissions of OC and EC are not specifically quantified in either the WRAP inventory or the NEI, but can be estimated as a percentage of PM_{10} emissions using data from EPA's SPECIATE database.[2] EC and OC are estimated to comprise 0.07% and 0.014% of PM_{10} emissions from catalytic cracking units, respectively; 38.4% and 24.7% of natural gas combustion PM_{10} emissions; and 1% each in oil combustion PM_{10}.

Table 10-2 lists potential control measures for emissions of SO_2, NO_X, and PM at petroleum refineries. The table includes options for process heaters, fluid catalytic cracking units, fluid coking operation boilers, coke calcining boilers, and flares.

Most of the SO_2 emissions from process heaters result from the burning of refinery fuel gases containing hydrogen sulfide (H_2S). These emissions can be reduced by treating the refinery fuel gas to remove H_2S before the gas is burned. A number of options are available to reduce NO_X emissions from process heaters. Combustion modifications including LNB, ULNB, and FGR reduce the formation of NO_X. In addition, flue gases from the process heaters can be treated with SCR or SNCR to reduce NO_X emissions. These post-combustion controls can be used either alone or in conjunction with combustion controls.[3,4]

In catalytic cracking, the heavier fractions of crude petroleum are treated with a catalyst which breaks the petroleum molecules into lighter compounds. The catalyst is continuously cycled between the cracking and a separate regeneration reactor in order to burn off coke build-up. Since the catalyst coke contains relatively high levels of sulfur, the combustion products from this coke are an important source of SO_2 emissions. Uncontrolled SO_2 concentrations in the fluid catalytic cracking (FCC) regenerator exhaust stream range from 150 to 3000 parts per million by volume (ppmv). The FCC regenerator burner also emits NO_X and PM, including material abraded from the catalyst (catalyst fines). Uncontrolled NO_X emissions from the regenerator vent can range from 50 to 400 ppmv.[5]

Table 10-1. Emissions from Petroleum Refineries in the WRAP Region

	AK	CA	CO	MT	ND	NM	NV	OR	UT	WA	WY	Tribes	All
						NO_X emissions (tons/year)							
Process Heaters	573	7,778	349	1,072	864	783	48		615	3,088	192	1	15,362
Catalytic Cracking Units		1,179	239	463		193			245				2,319
Flares	102	942	12	191		7			261	57	9		1,582
Fluid Coking Units		122		25									147
Other	122	563	106	103		31		7	105	996	1,156	1,984	5,174
Total	797	10,583	707	1,854	864	1,014	48	7	1,226	4,141	1,358	1,985	24,584
						SO_2 emissions (tons/year)							
Process Heaters	62	2,093	338	628	4,592	1,268	93		715	2,330	363	10	12,491
Catalytic Cracking Units		5,567	1,197	4,649		2,044			671	2,645	379		17,152
Flares	8	4,940	2	380		31			313	936	139		6,750
Fluid Coking Units		5,937		282									6,219
Coke Calcining		3,642								186			3,828
Incinerators	41	29		183		457		1	2,105	44	629		3,489
Other	41	5,802	126	183		688		10	2,105	698	5,238	113	15,003
Total	111	24,340	1,663	6,122	4,592	4,030	93	10	3,804	6,609	6,120	122	57,615
						PM_{10} emissions (tons/year)							
Process Heaters	30	1,049	31	38		72			61	200	28		1,509
Catalytic Cracking Units		305	264	333		171			30	74			1,177
Flares	6	41	0						2	5	0		55
Fluid Coking Units		154		6									160
Other	7	51	193	2				3	280	70	536		1,142
Total	43	1,600	488	379	0	244	0	3	373	349	564	0	4,042
						$PM_{2.5}$ emissions (tons/year)							
Process Heaters	2	1,026				64			60	30			1,184
Catalytic Cracking Units		278				103			4				384
Flares		41							2	1			44
Fluid Coking Units		140											140
Other	0	54							3	2			60
Total	2	1,539	0	0	0	167	0	0	70	33	0	0	1,812
						VOC emissions (tons/year)							
Fugitive emissions	0	3,094	127	1,326	0	1,396	20	37	447	955	469	1	7,872
Wastewater treatment	1,018	960	13	531	0	221	5	2	139	344	94	0	3,327
Process heaters	9	418	67	27	161	30	1	1	22	101	2,613	10	3,461
Flares	130	2,311	17	33	0	5	0	0	63	117	27	0	2,703
Other	11	1,304	43	100	0	151	8	1	67	161	7	0	1,852
Total	1,167	8,086	268	2,017	161	1,802	34	41	738	1,678	3,210	12	19,215

Table 10-2. Control Options for Petroleum Refineries

Source Type	Control Technology	Pollutant controlled	Baseline emissions (1000 tons)	Estimated control effieiency (%)	Potential emission reduction (1000 tons/year)	Refer-ences
Process heaters	Fuel treatment to remove sulfur	SO_2	12	up to 90	0 - 11	5,13
	LNB	NO_X	15	40	6.1	3,6
	ULNB	NO_X	15	75 - 85	12 - 13	5,6,3
	LNB and FGR	NO_X	15	48	7.4	3,6
	SNCR	NO_X	15	60	9.2	3,5,3
	SCR	NO_X	15	70 - 90	11 - 14	3,5,3
	LNB and SCR	NO_X	15	70 - 90	11 - 14	3,5,3
Fluid catalytic cracking units	Catalyst additives for NO_X reduction	NO_X	2.3	46	1.1	5,7
	LoTOX™	NO_X	2.3	85	2.0	5,8
	SNCR	NO_X	2.3	40 - 80	0.93 - 1.9	5,7
	SCR	NO_X	2.3	80 - 90	1.9 - 2.1	8,7
	Catalyst additives for SO_2 absorbtion	SO_2	17	20 - 60	3.4 - 10	5,7
	Desulfurization of catalytic cracker feed	SO_2	17	up to 90	0 - 15	7,13
	Wet scrubbing	SO_2	17	70 - 99	12 - 17	5,6,9
	ESP	PM_{10}	1.2	95+	1.1 - 1.2	5,6,10
		$PM_{2.5}$	0.4	95+	0.4	
		EC	0.0008	95+	0.0008	
		OC	0.0002	95+	0.0002	
Coking or coke calcining boilers	Spray dryer absorber	SO_2	10	80 - 95	8 - 10	5
	Wet FGD	SO_2	10	90 - 99	9 - 10	5,11,12
Flares	Improved process control and operator training	SO_2		varies		5
	Expand sulfur recovery unit	SO_2		varies		5
	Flare gas recovery system	SO_2		varies		5

Many refineries use catalyst additives to reduce SO_2 and NO_X emissions from fluid catalytic cracking units. SO_2 emissions can also be reduced by treating the fluid catalytic cracker feed stream to remove sulfur compounds. Some refineries in the U.S. have also used SCR to control NO_X emissions from catalytic cracking units, and one refinery in Japan has also used SNCR.[6,7] In addition, the LoTOx™ process has been developed to control NO_X emissions in the catalytic cracking regenerator offgas. In this system, ozone is injected into the offgas to convert the nitrogen oxide (NO) and nitrogen dioxide (NO_2) which comprise NO_X into more highly oxidized forms of nitrogen such as dinitrogen pentoxide (N_2O_5). These more highly oxygenated compounds are more soluble in water, and are removed from the offgas stream in a wet scrubber. An emission control efficiency of 90% has been reported for this system.[5,8] However, the LoTOx™ system is more cost effective if used in conjunction with a wet scrubber to control SO_2 emissions. Wet scrubbers are often used for simultaneous control of PM, SO_2, and NO_X emissions from the catalyst regenerator.[9] In addition, cyclones and ESP are commonly used to control PM emissions in the catalyst regenerator offgas.[5,10]

SO_2 emissions from fluid coking and coke calcining operations result from the combustion of a portion of the coke in a coke burner. Wet scrubbers have been used to control SO_2 emissions from the coking unit, with reported efficiencies of 95% to over 99%.[11] The emission streams from a coke calciner incinerator and from the coke burner in a fluid coking unit are similar to the emission streams from a boiler.[11] Therefore, it is believed that NO_X emissions from these streams can be controlled using SCR or SNCR.[12,13]

Petroleum refineries use flares to burn combustible gases that must be vented from various processes and cannot be practically processed or recovered. These gases generally emanate from non-steady-state operations, such as start-up, shut-down, process maintenance, and process upsets. Some of these operations are predictable, and others are not. SO_2 emissions from flaring result from the flaring of sour gases or other gases which have high concentrations of sulfur compounds. These emissions can often frequently be reduced through the use of improved process controls or improved training of process operators. Emissions can also be reduced by expanding the sulfur recovery unit to handle all of the acid gases produced by the refinery, and by optimizing the performance of the sulfur recovery unit. All of these measures are designed to reduce the number of times that sulfur-containing gases are flared.[5]
A flare gas recovery system can also be used to capture waste gases before they are flared, and hold the gases until they can be treated to remove sulfur compounds.[5] NO_X emissions during flaring events can be mitigated by combustion controls such as steam injection.

10.1 Factor 1 – Costs

Table 10-3 provides cost estimates for the emission control options which have been identified for petroleum refineries. 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 and annual cost figures are expressed in terms of the cost per unit process throughput.

Table 10-3. Estimated Costs of Control Petroleum Refineries

Source Type	Control Technology	Pollutant controlled	Estimated control effieiency (%)	Estimated capital cost ($1000/unit)	Estimated annual cost ($/year/unit)	Units	Cost effectiveness ($/ton)	Refer-ences
Process heaters	Fuel treatment to remove sulfur	SO_2	up to 90	3.4 - 10	28,000 - 36,000	Refinery capacity, 1000 barrels/day	1,300 - 1,700	5,13
	LNB	NO_X	40	2.7 - 7.6	290 - 810	MM-Btu/hr	650 - 2,800	3,6
	ULNB	NO_X	75 - 85	2.8 - 13	300 - 1,300	MM-Btu/hr	400 - 2,000	3,5,6
	LNB and FGR	NO_X	48	5.8 - 16	640 - 1,700	MM-Btu/hr	1,000 - 2,600	3,6
	SNCR	NO_X	60	5.2 - 22	570 - 2,400	MM-Btu/hr	890 - 5,200	3,5,6
	SCR[b]	NO_X	70 - 90	33 - 48	3,700 - 5,600	MM-Btu/hr	2,900 - 6,700	3,5,6
	LNB and SCR	NO_X	70 - 90	37 - 55	4,000 - 6,300	MM-Btu/hr	2,900 - 6,300	3,5,6
Fluid catalytic cracking units	Catalyst additives for NO_X reduction	NO_X	46		not available[a]			5,7
	LoTOX™	NO_X	85				1,700 - 2,000	5,8
	SNCR	NO_X	40 - 80				2500	5,7
	SCR	NO_X	80 - 90				2500	7,8
	Catalyst additives for SO_2 absorbtion	SO_2	20 - 60		not available[a]			5,7
	Desulfurization of catalytic cracker feed	SO_2	up to 90	23 - 54	190,000 - 250,000	Refinery capacity, 1000 barrels/day	6,200 - 8,000	7,13
	Wet scrubbing	SO_2	70 - 99				1,500 - 1,800	5,6,9
	ESP	$PM_{2.5}$, PM_{10}, EC,OC	95+				>10,000	5,6,10
Coking or coke calcining boiler offgas	Spray dryer absorber	SO_2	80 - 95				1,500-1,900	5
	Wet FGD	SO_2	90 - 99				1,500 - 1,800	5,11,12
Flares	Improved process control and operator training	SO_2	Varies		not available[a]			5
	Expand sulfur recovery unit	SO_2	Varies		not available[a]			5
	Flare gas recovery system	SO_2	Varies		not available[a]			5

[a]Costs of process modifications will depend on the specific refinery configuration.

[b]SCR cost estimates for SCR apply to mechanical draft heaters. Natural draft heaters would have to be converted to mechanical draft for installation of SCR. This would increase both the capital and annualized costs of control by about 10%.

Sulfur recovery units are believed to be more cost-effective than post-combustion controls for reducing SO_2 emissions from flares and incinerators at natural gas processing facilities. Recent analyses of controls for Regional Haze precursors have focused on add-on controls for SO_2, rather than such process modifications. However, costs of sulfur recovery units were estimated in an earlier study of model refineries in different size ranges.[14] These estimates have been updated to current dollars using the Chemical Engineering plant cost index.

Table 10-3 shows a range of values for each cost figure, since the cost per unit of throughput will depend on the process size and other factors. The lower ends of the cost ranges typically reflect larger engine or process sizes, and the higher ends of the cost ranges typically reflect smaller process sizes. The table also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

10.2 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 ICAC has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control.[15] However, state regulators' experience indicates that closer to 18 months is required to install this technology.[16] In the CAIR analysis, EPA estimated that approximately 30 months is required to design, build, and install SO_2 scrubbing technology for a single emission source.[17] 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 achieve emission reductions for oil refineries estimated at a total of 6½ years.

10.3 Factor 3 – Energy and Other Impacts

Table 10-4 shows the estimated energy and non-air pollution impacts of control measures for sources at petroleum refineries. Process modifications to desulfurize process gases burned in process heaters would generally require increases in catalytic hydrotreatment processing. These modifications may increase the generation of spent catalyst, which would need to be treated as a solid waste or a hazardous waste. Low NO_X burners for process heaters are expected to improve overall fuel efficiency.[3] FGR would require additional electricity to recirculate the fuel gas into the heater. In SCR systems for process heaters or other sources, fans would be required to overcome the pressure drop through the catalyst bed. The fans would require electricity, with resultant increases in CO_2 to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal.[10]

Catalyst additives for reducing NO_X and SO_2 emissions from fluid catalytic cracking units are likely to result in increased generation of spent catalyst, which would have to be disposed as hazardous waste. These catalyst additives may also result in increases in fuel consumption. However, information is not available to quantify these impacts. A LoTOx

Table 10-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Petroleum Refineries

Source Type	Control Technology	Pollutant controlled	Potential emission reduction (1000 tons/year)	Additional fuel requirement (%)	Energy and non-air pollution impacts (per ton of emission reduced)				
					Electricity requirement (kW-hr)	Steam requirement (tons steam)	Solid waste produced (tons waste)	Wastewater produced (1000 gallons)	Additional CO_2 emitted (tons)
Process heaters	Fuel treatment to remove sulfur	SO_2	0 - 11	b					b
	LNB	NO_X	6	a	e				
	ULNB	NO_X	12 - 13	a	e				
	LNB and FGR	NO_X	7.4		3,300				3.3
	SNCR	NO_X	9.2	0.16	460				3.2
	SCR	NO_X	11 - 14		8,400		0.073		8.4
	LNB and SCR	NO_X	11 - 14		8,400		0.073		8.4
Fluid catalytic cracking units	Catalyst additives for NO_X reduction	NO_X	1.1	d			d		
	LoTOX™	NO_X	2.0		d		d	d	
	SNCR	NO_X	0.93 - 1.9		460				3.2
	SCR	NO_X	1.9 - 2.1		8,400		0.073		8.4
	Catalyst additives for SO_2 absorbtion	SO_2	3.4 - 10	d			d		
	Desulfurization of catalytic cracker feed	SO_2	0 - 15	d		d	d		d
	Wet scrubbing	SO_2	12 - 17		1,100	3.1		3.7	2.6
	ESP	$PM_{2.5}$, PM_{10}, EC,OC	1.1 - 1.2		97		1		0.1
Coking or coke calcining boiler offgas	Spray dryer absorber	SO_2	8 - 10		400				1.1
	Wet FGD	SO_2	9 - 10		1,100	3.1		3.7	2.6
Flares	Improved process control and operator training	SO_2	Varies						
	Expand sulfur recovery unit	SO_2	Varies	d	d	d			d
	Flare gas recovery system	SO_2	Varies	d	d	d			d

NOTES:

blank indicates no impact is expected.

[a]The measure is expected to improve fuel efficiency.

[b]CO_2 from the generation of electricity would be offset by avoided emissions due to replacing the diesel engine

[c]EPA has estimated that the control measures used to meet Tier 4 standards will be integrated into the engine design so that sacrifices in fuel economy will be negligible.

[d]Some impact is expected but insufficient information is available to evaluate the impact.

[e]Some designes of low-NOX burners and ultralow-NOX burners require the use of pressurized air supplies. This would require additional electricity to pressurize the combustion

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 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.

Sulfur recovery units require electricity and steam. Wet or dry scrubbers applied to incinerators and tail gas treatment units applied to sulfur recovery units would use electricity for the fan power needed to overcome the scrubber pressure drop. These systems would also produce solid waste, and wet scrubbers would produce wastewater which would require treatment.

10.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of processes at petroleum refineries in the WRAP region. However, industrial processes often refurbished 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 this category. In the case of add-on technologies, the projected lifetime is 15 years.

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

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