Candidate SO₂ Control Measures for Industrial Sources in the LADCO Region

By

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Executive Summary

This report examines the inventory of SO_2 emissions and the candidate SO_2 control measures in the LADCO Region for industrial sources. The methodology and results are described below.

Chapter One – Source Categories and Emissions Inventories

LADCO Region States – Illinois, Indiana, Michigan, Minnesota, Ohio and Wisconsin provided recent inventory data for sources emitting one ton per year or greater. Source category codes and the total estimated emissions were included in the data from each state. Total state emissions are shown in Table E-1. Emissions were also evaluated by source category, as shown in Table E-2. The following are key conclusions of the assessment of the emissions inventory.

- Coal fired boilers contribute over half of the industrial SO_2 emissions to the LADCO Region.
- Cement manufacturing, by-product coke plants, petroleum refineries, lime manufacturing, boilers firing other fuels (coke oven gas, petroleum coke, etc.), and ferrous metals manufacturing all contribute 4% or more to the total region industrial SO_2 emissions. Each of these industries was examined in more detail to see what specific sources in these industries pose the best opportunities for SO_2 reduction.
- Other industries examined in more detail – chemical manufacturing, pulp & paper, glass manufacturing, brickmaking, and asphalt manufacturing, each contribute less in total SO_2 emissions, but may have specific sources that have high emissions.

Table E-1. Industrial Source SO_2 Emissions by State

State	Sum of Emissions (tpy)	Number of Sources	Year of Estimate
IL	65,340	441	2010
IN	63,932	384	2009
MI	33,190	272	2009
MN	15,108	289	2009
OH	100,976	141	2007
WI	80,096	383	2010
Grand Total	**358,641**	**1,910**	

Table E-2. Total Emissions by Source Category

Source Category	Sum of Emissions (tpy)	Percent of Total TPY	Count of Sources	Avg tpy/source
Fuel Comb - Industrial Boilers, ICEs - Coal	181,703	50.7%	144	1,262
Fuel Comb - Comm/Institutional - Coal	22,510	6.3%	65	346
Industrial Processes - Cement Manuf	18,515	5.2%	20	926
By-product Coke Manuf	16,517	4.6%	30	551
Industrial Processes - Petroleum Refineries	16,297	4.5%	173	94
Lime Manuf /Calcining	16,270	4.5%	28	581
Fuel Comb - Industrial Boilers, ICEs - Other	15,899	4.4%	137	116
Industrial Processes - Ferrous Metals	14,400	4.0%	181	80
Industrial Processes - Non-ferrous Metals	10,657	3.0%	63	169
Industrial Processes - Chemical Manuf	8,975	2.5%	67	134
Mineral Processing & Mineral Wool*	8,468	2.4%	32	265
Industrial Processes - Pulp & Paper	5,795	1.6%	56	103
Other Industrial Processes	4,940	1.4%	177	28
Fuel Comb - Industrial Boilers, ICEs - Oil	4,751	1.3%	226	21
Glass	3,679	1.0%	33	111
Waste Disposal	3,410	1.0%	171	20
Brick	1,546	0.4%	9	172
In-Process Fuel Use /Process Gas /Coke Oven or Blast Furnace	1,056	0.3%	9	117
Fuel Comb - Industrial Boilers, ICEs - Biomass	746	0.2%	41	18
Asphalt	596	0.2%	103	6
Industrial Processes - Oil & Gas Production	539	0.2%	5	108
Fuel Comb - Industrial Boilers, ICEs - Natural Gas	503	0.1%	48	10
Industrial Processes - Storage and Transfer	462	0.1%	25	18
Fuel Comb - Comm/Institutional - Other	174	0.0%	35	5
Fuel Comb - Comm/Institutional - Oil	154	0.0%	21	7
Fuel Comb - Comm/Institutional - Biomass	29	0.0%	3	10
Solvent - Industrial Surface Coating & Solvent Use	28	0.0%	3	9
Fuel Comb - Comm/Institutional - Natural Gas	23	0.0%	5	5
Grand Total	**358,641**		**1,910**	

* includes petroleum coke calciners

Chapter Two – Industrial Processes and Process Modifications

Chapter Two of this report examines each of the following industries/source categories in greater detail to identify the key sources of SO_2 emissions within these industries and to identify possible opportunities for reducing SO_2 emissions through fuel changes, process modifications, or changes in raw materials.

- Industrial, Commercial & Institutional (ICI) Boilers – The largest source of SO_2 emissions are ICI boilers, and especially coal fired boilers. This section explores the potential for fuel changes to lower sulfur fuels as well as furnace methods of reducing SO_2 emissions.
- Cement Kilns – This section identifies the types of kilns in the region and characterizes them with respect to emissions. Although all types of cement kilns exist in the LADCO region, the largest in number are long dry kilns. Feed materials are the largest source of SO_2, rather than fuel sulfur. Therefore, management of feed materials may be an option for reducing SO_2 emissions.
- Petroleum Refineries – The data shows that the largest sources for SO_2 emissions are the fluid catalytic cracking unit. This section explores the methods available for control of SO_2 emissions.
- Glassmaking facilities – Glassmaking facilities are mostly gas fired. So, much of the SO_2 results from sulfur in the raw materials that is released and oxidized in the melting furnaces. Raw material management is therefore an approach for SO_2 mitigation from the glass industry.
- Asphalt – Concrete Asphalt dryers and Asphalt Blowers are the largest sources of SO_2, largely resulting from sulfur in the fuel. Asphalt dryers can also reduce SO_2 by addition of alkaline materials to the mix.
- Chemicals – Carbon black manufacturing, sulfur plants and sulfuric acid plants are the largest sources of SO_2. Methods to reduce SO_2 emissions for these sources are explored in this section.
- Coke manufacturing – By product coke manufacturing is a significant source of SO_2 emissions. In fact, if the SO_2 emissions from industrial boilers that fire coke oven gas were included, coke manufacturing would be a significantly higher contributor. Coke oven gas can be cleaned. Some facilities in the region already employ COG cleaning.
- Lime Kilns – Lime kilns are also significant contributors to SO_2. Most of the SO_2 is from oxidation of sulfur in the limestone. Therefore, changes in limestone sources, if possible, are a method of control.
- Brickmaking facilities – SO_2 from brickmaking is primarily from oxidation of sulfur in the raw materials during the drying and curing process. Reduction of sulfur in the raw materials or increase in alkaline composition is therefore an approach to SO_2 emission reduction.
- Pulp and Paper – The largest sources of SO_2 emissions (not including fossil fueled power boilers) are the recovery furnaces. SO_2 emissions can be controlled to some degree by process changes to ensure that more sulfur remains in the smelt; however, this may be limited to some degree for a particular boiler. Other sources include the lime kiln and the pulping digesters.
- Ferrous Metals, including Taconite Plants – There are a number of sources that have significant SO_2 emissions, to include the cast house, taconite indurating furnaces, electric arc and ferroalloy furnaces. Taconite indurating furnaces are the largest individual sources of SO_2 emissions.
- Petroleum Coke calciners – There are two petroleum coke calciners that are high SO_2 emitters.

Chapter Three – Gas Treatment Technologies

This chapter addresses SO_2 capture technologies, especially wet FGD, dry FGD and Dry Sorbent Injection (DSI) and the costs of utilizing these technologies. Gas treatment technologies are important because it may not be economically or technically feasible to change a fuel, process, or raw materials. For example, if a cement plant has high sulfur in its limestone, it probably is not economically viable to change the limestone because the cement plant is built on the limestone quarry. For this reason it may be necessary to install a scrubber to reduce SO_2 emissions.

Most of the industrial sources of SO_2 discussed in this report have some form of existing PM controls – a fabric filter (or, baghouse), an ESP, or a venturi scrubber. In each of these cases it may be possible to inexpensively add SO_2 capture capability, either by addition of DSI (upstream of the ESP or fabric filter) or by addition of sodium reagent (to the scrubber). Where this is feasible, SO_2 reductions are expected to be possible at costs under \$1000/ton of SO_2 reduced.

Chapter Four - Other Methods for Mitigating the Effects of SO_2 Emissions

This chapter discusses methods to mitigate the effects of SO_2 emissions in the event that SO_2 emissions cannot be reduced further. These methods discuss the benefits of increased pollutant dispersion through increased stack height, mitigation of building downwash effects through building modifications, or limiting access to areas affected by high concentrations. All of these approaches can be assessed through air modeling.

Chapter One - SO₂ Source Categories and Emissions Inventories

LADCO has identified the following source categories as potentially of interest for SO_2 reductions:

- Industrial, Commercial, Institutional (ICI) Boilers
- Portland Cement Plants
- Petroleum Refineries
- Glassmaking facilities
- Asphalt plants
- Chemical plants

LADCO provided emissions information from the states: Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin. In this effort, we used the most recent data available from the particular state. The total SO_2 emissions, number of sources, and date of emissions, are shown in Table 1.

Table 1. Industrial Source SO_2 Emissions by State

State	Sum of Emissions (tpy)	Number of Sources	Year of Estimate
IL	65,340	441	2010
IN	63,932	384	2009
MI	33,190	272	2009
MN	15,108	289	2009
OH	100,976	141	2007
WI	80,096	383	2010
Grand Total	358,641	1,910	

The data was sorted by source category code for non EGU point source emissions for each state and the results for different source types are shown in Table 2, ranked from largest contributor to total SO_2 emissions to the lowest contributor to total SO_2 emissions. The second largest source category, Industrial Processes – NEC, includes two source categories that were identified to be of interest – asphalt plants and glassmaking facilities – but also some other significant contributors to SO_2 emissions in the region, and these are shown in Table 3.

The source category that contributes the greatest amount to non-EGU SO_2 emissions is industrial coal-fired boilers, and when the contribution of commercial and institutional boilers is included, the contribution of fuel combustion in boilers is well over half of the total regional industrial inventory. In addition to the categories identified as of interest, coke production,

especially by-product coke production, Lime manufacture, and ferrous and non-ferrous metal manufacturing are significant contributors to the region's SO$_2$ emissions.

Table 2. Source Types within the LADCO region, SO$_2$ emissions and number of sources

Source Category	Sum of Emissions (tpy)	No. of sources
Fuel Comb - Industrial Boilers, ICEs - Coal	181,703	144
Industrial Processes - NEC	53,071	421
Fuel Comb - Comm/Institutional - Coal	22,510	65
Industrial Processes - Cement Manuf	18,515	20
Industrial Processes - Petroleum Refineries	16,297	173
Fuel Comb - Industrial Boilers, ICEs - Other	15,899	137
Industrial Processes - Ferrous Metals	14,400	181
Industrial Processes - Non-ferrous Metals	10,657	63
Industrial Processes - Chemical Manuf	8,975	67
Industrial Processes - Pulp & Paper	5,795	56
Fuel Comb - Industrial Boilers, ICEs - Oil	4,751	226
Waste Disposal	3,410	171
Fuel Comb - Industrial Boilers, ICEs - Biomass	746	41
Industrial Processes - Oil & Gas Production	539	5
Fuel Comb - Industrial Boilers, ICEs - Natural Gas	503	48
Industrial Processes - Storage and Transfer	462	25
Fuel Comb - Comm/Institutional - Other	174	35
Fuel Comb - Comm/Institutional - Oil	154	21
Fuel Comb - Comm/Institutional - Biomass	29	3
Solvent - Industrial Surface Coating & Solvent Use	28	3
Fuel Comb - Comm/Institutional - Natural Gas	23	5
Grand Total	**358,641**	**1,910**

Table 3. Industrial Processes – NEC, SO$_2$ Emissions and number of sources

Industrial Processes - NEC	Sum of Emissions (tpy)	No. of sources
By-product Coke Manuf	16,517	30
Lime Manuf /Calcining	16,270	28
Mineral Processing & Mineral Wool (includes 2 petroleum coke calciners)	8,468	32
Other	4,940	177
Glass	3,679	33
Brick	1,546	9
In-Process Fuel Use /Process Gas /Coke Oven or Blast Furnace	1,056	9
Asphalt	596	103
Grand Total	**53,071**	**421**

Tables 4 shows a breakdown of SO$_2$ emissions by source category for each state in the LADCO region.

Table 4. Emissions by State and Source Type

	Sum of Emissions (tpy)	No. of sources
IL	**65,340**	**441**
Fuel Comb - Industrial Boilers, ICEs - Coal	29,577	24
Industrial Processes - NEC	18,503	164
Industrial Processes - Petroleum Refineries	6,115	58
Fuel Comb - Comm/Institutional - Coal	4,497	19
Waste Disposal	1,596	47
Industrial Processes - Chemical Manuf	1,509	32
Industrial Processes - Cement Manuf	1,208	2
Industrial Processes - Ferrous Metals	833	20
Fuel Comb - Industrial Boilers, ICEs - Other	546	16
Industrial Processes - Non-ferrous Metals	387	10
Industrial Processes - Oil & Gas Production	372	1
Fuel Comb - Industrial Boilers, ICEs - Oil	67	19
Industrial Processes - Storage and Transfer	32	7
Fuel Comb - Comm/Institutional - Other	26	4
Solvent - Industrial Surface Coating & Solvent Use	24	1
Fuel Comb - Comm/Institutional - Natural Gas	17	3
Fuel Comb - Industrial Boilers, ICEs - Natural Gas	16	7
Fuel Comb - Comm/Institutional - Oil	14	7
IN	**63,932**	**384**
Fuel Comb - Industrial Boilers, ICEs - Coal	16,118	23
Industrial Processes - NEC	14,720	88
Fuel Comb - Comm/Institutional - Coal	9,493	16
Fuel Comb - Industrial Boilers, ICEs – Other	8,103	60
Industrial Processes - Non-ferrous Metals	5,179	27
Industrial Processes - Cement Manuf	4,451	9
Industrial Processes - Ferrous Metals	3,138	52
Industrial Processes - Chemical Manuf	891	10
Industrial Processes - Petroleum Refineries	628	21
Fuel Comb - Industrial Boilers, ICEs - Oil	518	30
Industrial Processes - Storage and Transfer	337	13
Waste Disposal	170	18
Industrial Processes - Oil & Gas Production	81	3
Fuel Comb - Industrial Boilers, ICEs - Natural Gas	58	5
Fuel Comb - Industrial Boilers, ICEs - Biomass	27	4
Fuel Comb - Comm/Institutional - Other	9	1
Industrial Processes - Pulp & Paper	5	1
Fuel Comb - Comm/Institutional - Oil	5	3

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	Sum of Emissions (tpy)	No. of sources
MI	**33,190**	**272**
Industrial Processes - Cement Manuf	11,031	7
Fuel Comb - Industrial Boilers, ICEs - Coal	7,557	23
Industrial Processes - NEC	3,495	38
Fuel Comb - Comm/Institutional - Coal	2,811	4
Industrial Processes - Ferrous Metals	2,274	23
Fuel Comb - Industrial Boilers, ICEs - Other	2,236	28
Industrial Processes - Non-ferrous Metals	1,059	7
Waste Disposal	818	42
Fuel Comb - Industrial Boilers, ICEs - Oil	693	28
Industrial Processes - Petroleum Refineries	625	27
Fuel Comb - Industrial Boilers, ICEs - Biomass	194	7
Industrial Processes - Chemical Manuf	147	3
Industrial Processes - Oil & Gas Production	86	1
Fuel Comb - Comm/Institutional - Oil	46	4
Fuel Comb - Comm/Institutional - Other	36	4
Industrial Processes - Pulp & Paper	32	8
Fuel Comb - Industrial Boilers, ICEs - Natural Gas	28	14
Fuel Comb - Comm/Institutional - Biomass	19	2
Solvent - Industrial Surface Coating & Solvent Use	4	2
MN	**15,108**	**289**
Fuel Comb - Industrial Boilers, ICEs - Coal	4,099	22
Industrial Processes - Ferrous Metals	3,881	37
Industrial Processes - NEC	1,957	48
Industrial Processes - Non-ferrous Metals	1,539	3
Fuel Comb - Industrial Boilers, ICEs - Oil	1,279	43
Industrial Processes - Petroleum Refineries	653	52
Fuel Comb - Industrial Boilers, ICEs - Natural Gas	370	17
Waste Disposal	350	29
Fuel Comb - Industrial Boilers, ICEs - Biomass	319	10
Industrial Processes - Chemical Manuf	316	6
Fuel Comb - Industrial Boilers, ICEs - Other	152	4
Fuel Comb - Comm/Institutional - Coal	100	6
Fuel Comb - Comm/Institutional - Oil	53	5
Industrial Processes - Pulp & Paper	29	5
Fuel Comb - Comm/Institutional - Biomass	10	1
Industrial Processes - Storage and Transfer	1	1

	Sum of Emissions (tpy)	No. of sources
OH	**100,976**	**141**
Fuel Comb - Industrial Boilers, ICEs - Coal	57,955	8
Industrial Processes - NEC	11,338	39
Industrial Processes - Petroleum Refineries	8,138	10
Industrial Processes - Chemical Manuf	6,073	11
Fuel Comb - Comm/Institutional - Coal	4,649	3
Industrial Processes - Ferrous Metals	3,785	19
Fuel Comb - Industrial Boilers, ICEs - Other	2,464	7
Industrial Processes - Non-ferrous Metals	2,427	6
Industrial Processes - Cement Manuf	1,825	2
Fuel Comb - Industrial Boilers, ICEs - Oil	1,738	10
Industrial Processes - Pulp & Paper	219	3
Waste Disposal	156	8
Industrial Processes - Storage and Transfer	89	2
Fuel Comb - Industrial Boilers, ICEs - Biomass	36	3
Fuel Comb - Comm/Institutional - Oil	36	2
Fuel Comb - Industrial Boilers, ICEs - Natural Gas	31	5
Fuel Comb - Comm/Institutional - Other	12	1
Fuel Comb - Comm/Institutional - Natural Gas	6	2
WI	**80,096**	**383**
Fuel Comb - Industrial Boilers, ICEs - Coal	66,397	44
Industrial Processes - Pulp & Paper	5,510	39
Industrial Processes - NEC	3,058	44
Fuel Comb - Industrial Boilers, ICEs - Other	2,398	22
Fuel Comb - Comm/Institutional - Coal	959	17
Industrial Processes - Ferrous Metals	488	30
Fuel Comb - Industrial Boilers, ICEs - Oil	456	96
Waste Disposal	321	27
Fuel Comb - Industrial Boilers, ICEs - Biomass	171	17
Industrial Processes - Petroleum Refineries	138	5
Fuel Comb - Comm/Institutional - Other	91	25
Industrial Processes - Non-ferrous Metals	66	10
Industrial Processes - Chemical Manuf	39	5
Industrial Processes - Storage and Transfer	3	2
Grand Total all states	**358,641**	**1,910**

Chapter Two - Industrial Processes and Process Modifications

This chapter will briefly describe each industrial process, how SO_2 is generated from the process, and how it may be controlled through process modifications, fuel changes, raw material changes, etc.

- Industrial, Commercial, Institutional (ICI) Boilers
- Portland Cement Plants
- Petroleum Refineries
- Glassmaking facilities
- Asphalt plants
- Chemical plants
- Cokemaking facilities
- Lime and aggregate kilns
- Brickmaking facilities
- Pulp and paper mills
- Ferrous Metals, Iron and Steelmaking and Taconite production facilities
- Petroleum Coke Calcining Kilns

2.1 Industrial, Commercial, Institutional (ICI) Boilers

ICI boilers are used for a variety of applications ranging from producing steam for power generation, for heating or for process steam applications. These boilers may be located at industrial facilities, such as Pulp and Paper mills, oil refineries, steel mills, or at universities, hospitals, or other large complexes that generate their own power or generate steam. Table 5 lists SO_2 emissions from ICI boilers in the LADCO region. In some of the categories SO_2 emissions from internal combustion engines (ICEs: diesels, turbines and natural gas reciprocating engines) are included in the inventory, but these generally contribute a small portion of the total emissions due to the fuels they use. Fuels for ICI boilers include coal, oil, natural gas, and process gases. Coal-fired boilers are, by far, the largest source of SO_2 for boilers or for all industrial sources. As a result, they require special attention. Next in importance are boilers that fire coke oven gas, blast furnace gas, petroleum coke and other fuels. Oil, and particularly No. 6 and residual fuel oil, are important contributors to SO_2 emissions.

For boilers, SO_2 is generated from combustion of sulfur-bearing fuel. Coals burned in the region for all boiler types (including utility boilers) typically generate anywhere from about 0.50 lb SO2/million Btu for Powder River Basin coal to about 5 lb SO_2/million Btu for Illinois Basin coal. Emissions from combustion of oil will vary as well, depending upon the sulfur content of the oil. Process gases, such as coke oven gas, if not desulfurized, can result in substantial levels of SO_2 when burned. Therefore, changing fuels, or cleaning fuels in the case of process gases or some coals, are the principal means of reducing sulfur emissions without adding flue gas treatment methods, and these will be the focus of this chapter. The following sections will address:

- Availability of lower sulfur coal
- Cleaning of coal to reduce sulfur content
- Availability of low sulfur oil
- Gas cleaning to reduce sulfur content of process gas
- Limestone injection for CFBs

Table 5. Emissions from ICI boilers in the LADCO region

	Sum of emissions (tpy)	No. of sources
All Boilers/ICE's	**226,493**	**725**
Fuel Comb - Industrial Boilers, ICEs – Coal	**181,703**	**144**
Fuel Comb - Comm/Institutional – Coal	**22,510**	**65**
Fuel Comb - Industrial Boilers, ICEs – Other	**15,899**	**137**
Ext Comb /Industrial /Process Gas /Coke Oven Gas	8,392	27
Ext Comb /Industrial /Process Gas /Blast Furnace Gas	3,622	38
Ext Comb /Industrial /Solid Waste /Specify Waste Material in Comments	1,821	17
Ext Comb /Industrial /Petroleum Coke /Cogeneration	816	1
Ext Comb /Industrial /Solid Waste /Refuse Derived Fuel	687	1
Ext Comb/Other	533	46
Int Comb /Engine Testing /Reciprocating Engine /Gasoline	28	7
Fuel Comb - Industrial Boilers, ICEs – Oil	**4,751**	**226**
Ext Comb /Industrial /Residual Oil /Grade 6 Oil	3,158	49
Ext Comb /Industrial /Residual Oil /10-100 Million Btu/hr **	849	13
Ext Comb /Industrial /Distillate Oil /Grades 1 and 2 Oil	256	32
Ext Comb /Industrial /Distillate Oil /10-100 Million Btu/hr **	211	53
Int Comb/Total	192	72
Ext Comb /Industrial /Distillate Oil /< 10 Million Btu/hr **	49	3
Ext Comb /Industrial /Distillate Oil /Grade 4 Oil	25	1
Ext Comb /Industrial /Residual Oil /Grade 5 Oil	8	1
Ext Comb /Industrial /Distillate Oil /Cogeneration	2	1
Ext Comb /Space Heater /Industrial /Distillate Oil	2	1
Fuel Comb - Industrial Boilers, ICEs – Biomass	**746**	**41**
Fuel Comb - Industrial Boilers, ICEs - Natural Gas	**503**	**48**
Fuel Comb - Comm/Institutional – Other	**174**	**35**
Fuel Comb - Comm/Institutional – Oil	**154**	**21**
Fuel Comb - Comm/Institutional – Biomass	**29**	**3**
Fuel Comb - Comm/Institutional - Natural Gas	**23**	**5**

2.1.1 Availability of Lower Sulfur Coal

Most of the local coal burned in LADCO region industrial boilers is Illinois Basin (IL and IN) or Northern Appalachian (OH). These are generally higher in sulfur content than most other coals burned in the US, although some medium to low sulfur coals are available in the region or in neighboring states.[1]

Many power plants in the LADCO region have switched to low sulfur western coals. Use of these coals typically requires modifications to address the high dust generation and combustibility of coal dust from these coals (requiring baghouses on coal handling facilities) and other boiler modifications to address the low heating value and the different ash slagging characteristics of these coals. Transportation of western coals to industrial boilers in the LADCO region also poses a challenge. According to Reference 2, power plants in the Midwestern U.S. may be served by any one of several railroads (BNSF, CN, CP, CSX, NS, UP or short-line railroads). However, the rail network in the Midwestern U.S. is very complex, and most plants are served by only one of these railroads. Since only four railroads transport 90% of the coal in the US (BNSF and UP in the west and CSX and NS in the east),[3] it is likely that transfer charges will be incurred. Nevertheless, most power plants in the Midwest are capable of burning western coal, particularly because they have the ability to receive large quantities of coal in unit trains. A unit train is a train where all of the cars have the same origin and destination and no stops. Typical train sizes run over 100 cars. If a typical train is 100-120 cars and each car holds 100-120 tons of coal, this means that each delivery is 10,000-14,400 tons of coal. Unit train delivery of coal is therefore limited to very large facilities, such as very large industrial sites or power plants. Unfortunately, industrial boilers may not be as close to major rail lines, requiring additional transfer fees, and they are less likely to be on sites large enough to accept a unit train, and some may have coal delivered by truck. Since transportation rates are based on tonnage, higher transportation costs can make lower Btu coals, such as western coals, less attractive even if the cost at the mine is less. Therefore, when transporting coal a long distance, it is necessary to consider the transportation cost (per ton) and the heat value of the coal, as well as the cost at the mine.

Table 6 shows representative coal pricing at the mine for different coals, to include heat value (Btu/lb) and uncontrolled SO2 emissions (lb SO2/million Btu). Transportation costs would be added to determine the price as delivered.

Table 6. Coal Prices at the Mine

Average weekly coal commodity spot prices dollars per short ton at mine (*not including transportation*)				
Week Ended	Central Appalachia 12,500 Btu, 1.2 SO_2	Northern Appalachia 13,000 Btu, <3.0 SO_2	Illinois Basin 11,800 Btu, 5.0 SO_2	Powder River Basin 8,800 Btu, 0.8 SO_2	Uinta Basin 11,700 Btu, 0.8 SO_2
09-Sep-11	$80.15	$75.75	$47.80	$14.50	$41.00

Source: Energy Information Administration

Western coals, that are generally lower in sulfur than eastern coals, also tend to have lower heat values, making transportation a very critical issue for these coals. Because of these costs, it is important to transport western coals as far as possible via unit train or by barge (water transportation is generally the least expensive way to transport coal long distances). Therefore, the following approaches may be used to minimize transportation costs.

- *Accept barge delivery*. For Montana or Wyoming coals, coal could be delivered via Burlington Northern Santa Fe (BNSF) unit train for transloading to barge and delivery via river. BNSF has transloading partners on the Great Lakes and on the Mississippi. Utah or Colorado coal would likely be delivered by Union Pacific (UP) to Corpus Cristi, and could then be transloaded to barge up the Mississippi and delivered by river. Therefore, industrial facilities that are equipped to accept coal deliveries by barge could potentially accept western coal.

- *Accept a full unit train*. It would be necessary to be able to accept a full unit train, and unload within 24 hours unless the facility had its own rail car mover. This would only be possible at large industrial facilities with enough track to accept and/or store a unit train. The possible alternative would be if there was a local transloading facility that could accept a unit train of coal and distribute the coal via local carriers.

As a result, western coals are generally limited to very large facilities that can accept a unit train or those with barge delivery of coal.

Central and southern Appalachian coals, which are lower in sulfur than IL Basin or Northern Appalachian coals, but not as low in sulfur as the western coals, generally have high

heating value and are more accessible than western coals; however, these coals are generally more expensive than either Northern Appalachian or Illinois Basin coals and would incur additional transportation costs that would increase the cost of the coal over local coal that is higher in sulfur.

Some industrial facilities receive coal by truck. In this case, these facilities will be limited by transportation cost to local coal. The best option for reducing the sulfur content of the coal they burn may be cleaned coal.

2.1.2   Coal Cleaning

Because industrial boilers are more likely to use local coals, for many industrial boiler owners coal cleaning may be a more economically viable approach for reducing coal sulfur than purchase of lower sulfur coals from western states or from central Appalachia. Sulfur may be removed from the coal through cleaning measures that remove rock and pyrite (including pyritic sulfur). Most coals experience some form of cleaning prior to shipment in order to remove impurities and increase the heating value of the delivered coal. To the extent that sulfur may be in these impurities, such as in pyrites, sulfur can be removed as well; however, some sulfur is organically bound to the coal and cannot be removed, at least through physical separation. Physical cleaning measures rely on the difference in density between the impurities and the coal. Chemical cleaning measures chemically remove impurities.

Although most coal experiences some cleaning, coal cleaning for the purpose of reducing sulfur was once more widely used in power plants than it is today. Increased use of scrubbers on power plants and increased availability of lower sulfur western coals that do not require preparation has reduced demand for cleaned coal for power plant applications. Figure 1 shows a process flow diagram of a typical coal cleaning plant using physical coal cleaning. It is apparent from this diagram that there are many steps possible in physical coal cleaning, and the cost of cleaning will depend upon how many steps are employed to clean the coal. Run-of-mine (ROM) coal should be cleaned of rocks and other large debris, but removal of other mineral materials and impurities will normally require cleaning at finer size grades at added cost. Although some fines may be generated through handling, physical coal cleaning methods in common commercial practice will generally produce sizes of 1.5 inches, making the cleaned coal suitable for all industrial boiler applications.

According to EPA, for high sulfur coals (typical for Illinois Basin and Northern Appalachian coals), up to 60% sulfur (on a heating value basis) is removed through physical cleaning methods from uncleaned coal depending upon the coal and the practice used. For example, uncleaned coal that has an emission rate of 4.8 lb SO_2/MMBtu can be physically cleaned to achieve 1.9 lb SO_2/MMBtu, and 9.0 lb SO_2/MMBtu can be physically cleaned to achieve 3.5 lb SO_2/MMBtu.[4] However, 60% represents the best potential technology discussed in Reference 4 while common commercial practice reduces coal sulfur by about 40%. Higher sulfur reductions are possible if chemical cleaning methods are considered.

Current data was unavailable for the cost of coal cleaning. The Illinois Clean Coal Institute, US Geologic Survey (USGS) and DOE's Energy Information Administration were all contacted to find up-to-date information on the costs of coal cleaning. USGS performed a study that was published in 2009;[5] however, the detailed cost information was not released. According to USGS,[6] the work had been done several years prior and had not been kept up to date. According to Illinois Clean Coal Institute, an organization that sponsors research on clean coal, they are working primarily on lower sulfur western coals. As a result, cost information was not available for coal cleaning. However, because it has been used, it is certainly an approach that is available and feasible, and is likely to be economically viable for many industrial facilities.

Figure 1. Process Flow Diagram of a Typical Coal Cleaning Plant. [5]
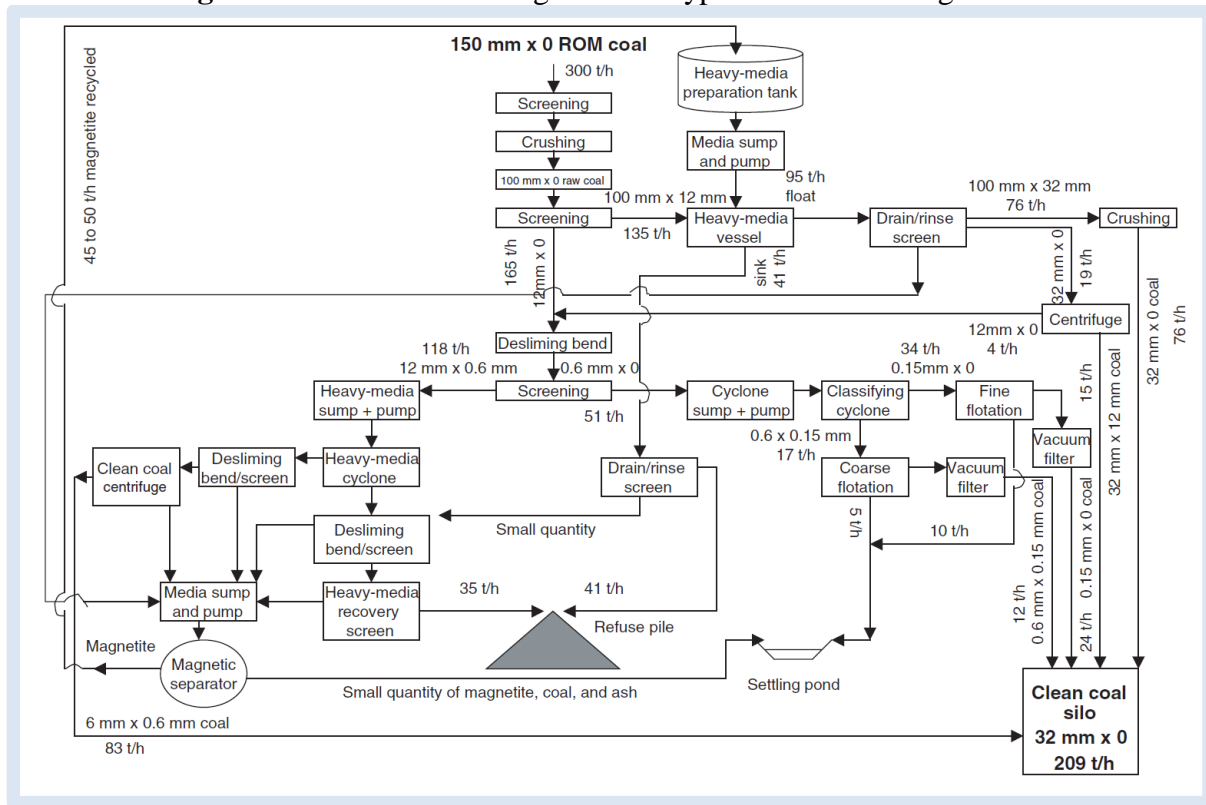
*Impact of Changing Coal on Other Pollutants*

Changing coals or cleaning coal will impact the emission of other pollutants. The impact is determined by the concentration of other trace pollutants (such as mercury, chlorine, metals, etc.) or constituents that impact criteria pollutant emissions (such as nitrogen). Cleaning will generally only have a positive impact on air emissions from burning the coal; however, coal cleaning does result in solid or liquid waste from cleaning.

2.1.3   Availability of Low Sulfur Oil

Because there are refineries in the Midwest that can produce different products, oil does not have the logistical issues that coal does. Because low and especially ultra-low sulfur diesel is increasing in use, refineries have been modifying their operations to produce these fuels. Some refineries are more easily retrofit for producing this product than others. So, it is unclear if the availability of ultra-low sulfur fuel has caused many facilities to switch fuels.   A task that was requested by LADCO members was to better understand the trends in fuel use to see if facilities were burning low and ultra-low sulfur diesel in lieu of higher sulfur fuels that their permits may currently allow.

As shown in Figure 2, which is developed from the emissions database, by far most of the SO_2 from oil fired ICI boilers is from burning residual fuel oil.   Due to the 1 tpy cut off used to develop the database, many commercial or institutional boilers that may be burning low sulfur fuels, are not included here. In any event, this shows that industrial boilers firing lower quality fuels (residual and No. 6) are the prime contributors to oil-fired industrial boiler SO_2 emissions.

Figure 2. SO_2 Emissions from LADCO Region Oil-Fired ICI Boilers (tpy)
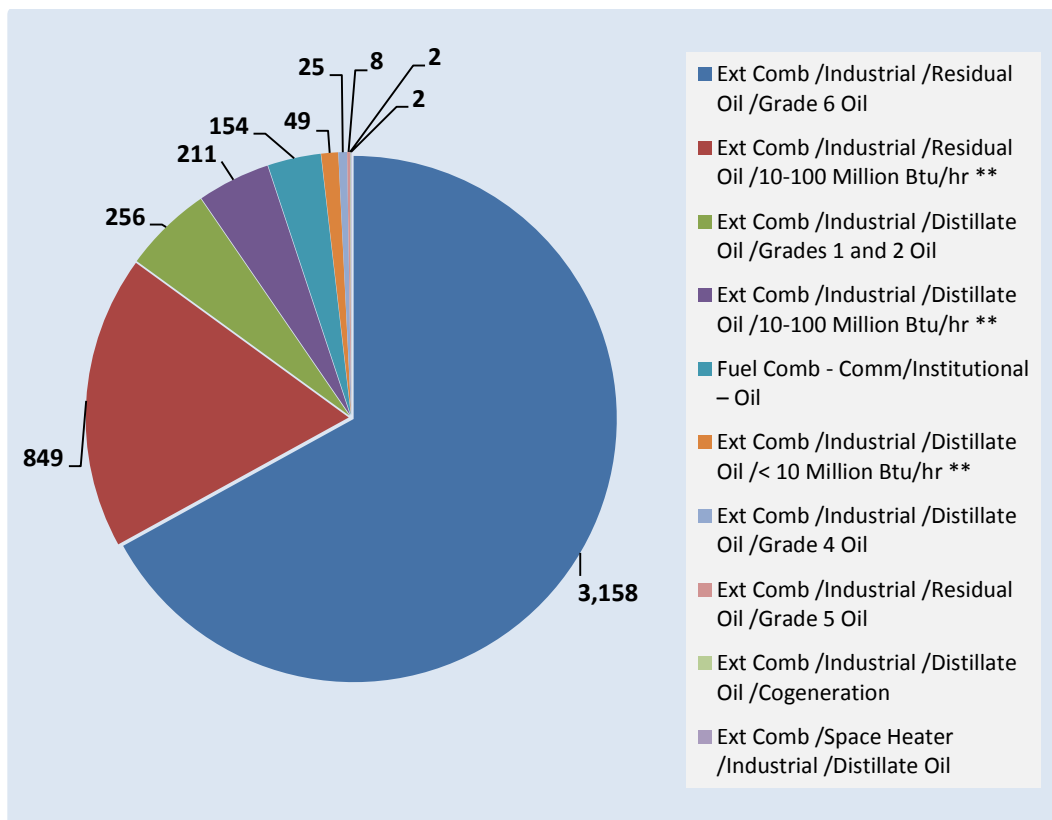
To examine trends in oil use in the LADCO region, data from the Energy Information Agency was collected. Figures 3a and3b and 4a and 4b show trends in industrial and commercial customer oil sales and industrial and commercial customer natural gas consumption in the LADCO region over the 1994-2009 time period (2009 is the most recent data available for the full region).[7] These figures show the total of oil sales to end users as well as to retailers for the particular end-user type (industrial or commercial). The figures shown here include fuel usage for all applications, since vehicular and off-road usage is not segregated from stationary source usage.

Industrial Users - Figure 3a shows that, except for low sulfur diesel fuel oil, consumption of all fuel oil types dropped off in 2009. Part of this is likely due to the recession in 2009 causing a reduction in activity. Although the trend for low sulfur diesel is generally up over the period, it is not enough to compensate for the reduction in demand for other fuels. As shown in Figure 3a, natural gas consumption over the same period also showed a slow falling-off trend. As a result, the reduction in use of some fuel oils is not explained by a switch to natural gas.

Commercial Users - Figure 4a shows that for commercial users the use of ultra-low sulfur diesel increased sharply in the period from 2005 to 2009, more than making up for the reduction in low sulfur diesel usage over that time. It is unclear how much of this was devoted to vehicle applications versus stationary source applications, such as boilers or fired heaters. Except for No. 2 distillate fuel oil, sales are generally down for most fuels. The total reduction in use of other fuels is too great to be explained by the increase in ultra-low sulfur diesel use alone. Figure 4b shows that natural gas consumption over the same period ranged between about 750,000 and 900,000 million scf, with an increase from 2006 to 2008. As a result, the reduction in use of some fuel oils may in part be explained by a switch to natural gas during the 2006 to 2008 period.

Trends in prices were examined. Increases in prices for all liquid fuels were observed, as demonstrated by Figure 5a, which shows the increase in residual fuel oil prices. Figure 5a also shows that recently the spread between residual fuel with under 1% sulfur and residual fuel with sulfur over 1% has reached about $0.50 per gallon. Figure 5b shows the price spread between ultra-low sulfur diesel and No. 2 fuel oil which has generally dropped over the past few years.

The data on emissions from oil fired boilers and the data on fuel sales seems to suggest that, while some users may have transitioned to ultra-low or low-sulfur diesel fuel due to a reduction in the spread in price with No. 2 fuel oil, this does not appear to be enough to explain the total reduction in use of other fuels. Data on natural gas usage does not indicate a broad trend toward that fuel from fuel oils. It is possible that the drop off in fuel oil use may be a result of the recent economic downturn, which may have reduced demand for fuel across the board.

Costs for switching fuels – Switching fuels from one distillate oil to another will entail minimal capital cost, especially if it is a permanent switch that does not require additional storage capability. Changing from a residual fuel or other heavy fuel to distillate may require some changes to atomizers to adjust for the lighter fuel, but this is a relatively small cost. Switching between natural gas and oil fuel will require burners that are capable of firing either fuel and would be a modest capital cost.

Estimated costs overall are primarily driven by differential prices in fuel. Costs have been estimated to be $1,200-$2,000/ ton of SO_2 reduced for conversion from distillate oil at 0.30% sulfur to 0.05% sulfur and $1,900-$3,800/ton of SO_2 reduced for conversion from 1.0% sulfur residual fuel oil to 0.5% sulfur residual fuel oil. [8]

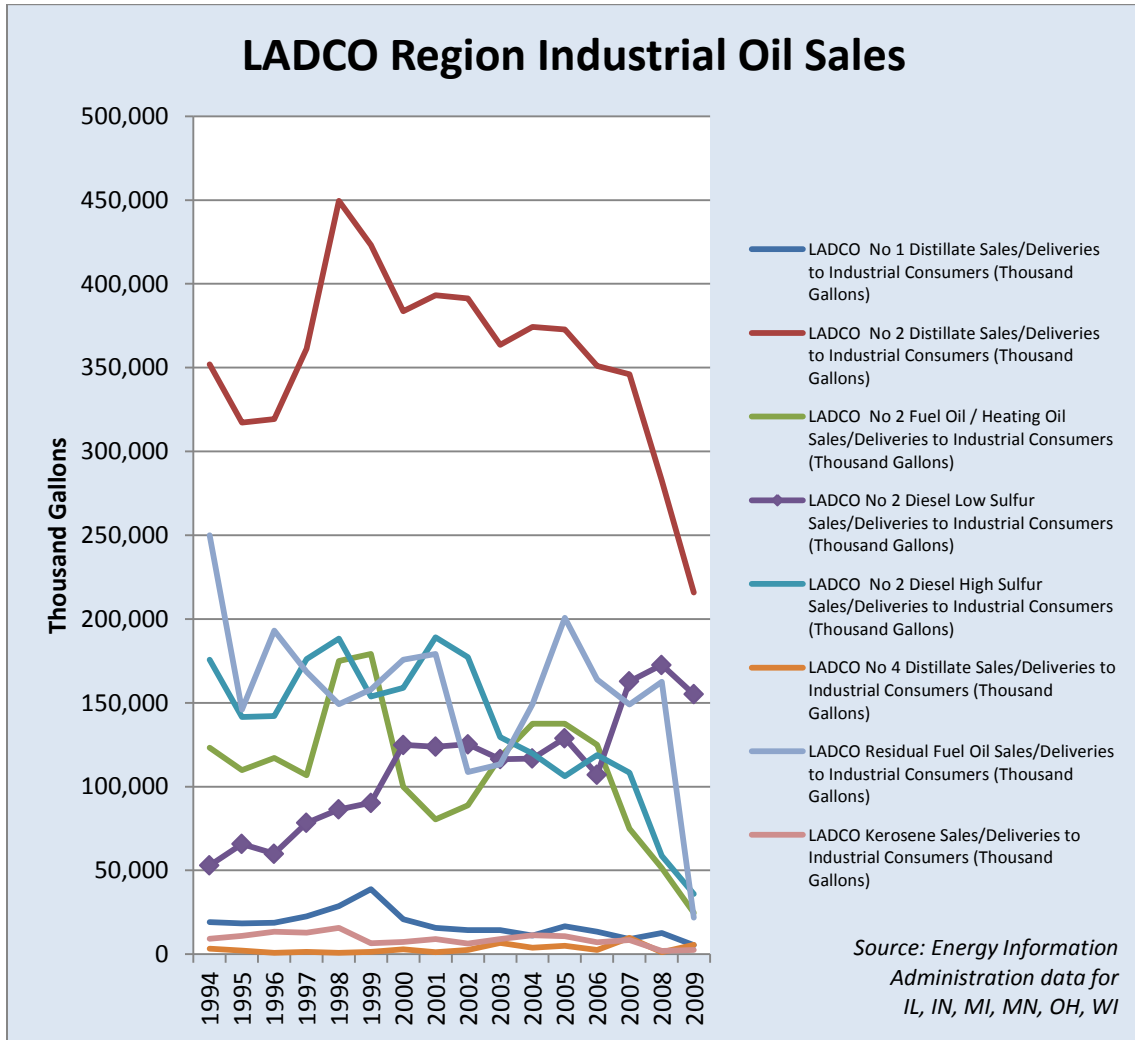**Figure 3a.** Oil Sales to Industrial Users in the LADCO Region

LADCO Region Industrial Oil Sales

Legend:
- LADCO No 1 Distillate Sales/Deliveries to Industrial Consumers (Thousand Gallons)
- LADCO No 2 Distillate Sales/Deliveries to Industrial Consumers (Thousand Gallons)
- LADCO No 2 Fuel Oil / Heating Oil Sales/Deliveries to Industrial Consumers (Thousand Gallons)
- LADCO No 2 Diesel Low Sulfur Sales/Deliveries to Industrial Consumers (Thousand Gallons)
- LADCO No 2 Diesel High Sulfur Sales/Deliveries to Industrial Consumers (Thousand Gallons)
- LADCO No 4 Distillate Sales/Deliveries to Industrial Consumers (Thousand Gallons)
- LADCO Residual Fuel Oil Sales/Deliveries to Industrial Consumers (Thousand Gallons)
- LADCO Kerosene Sales/Deliveries to Industrial Consumers (Thousand Gallons)

Source: Energy Information Administration data for IL, IN, MI, MN, OH, WI

Figure 3b. Trends in Industrial Natural Gas Consumption in the LADCO region.

LADCO Natural Gas Industrial Consumption (MMcf)

Source: Energy Information Administration data for IL, IN, MI, MN, OH, WI

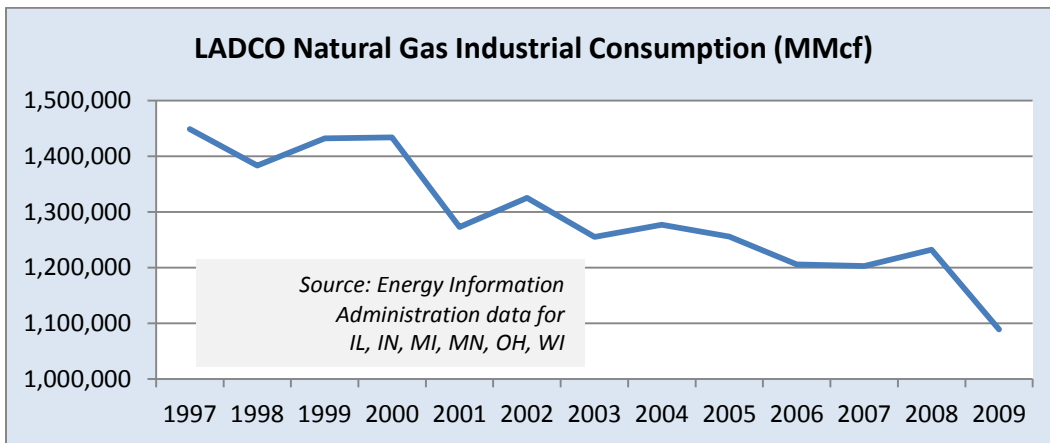**Figure 4.** Oil Sales to Commercial Users in the LADCO Region
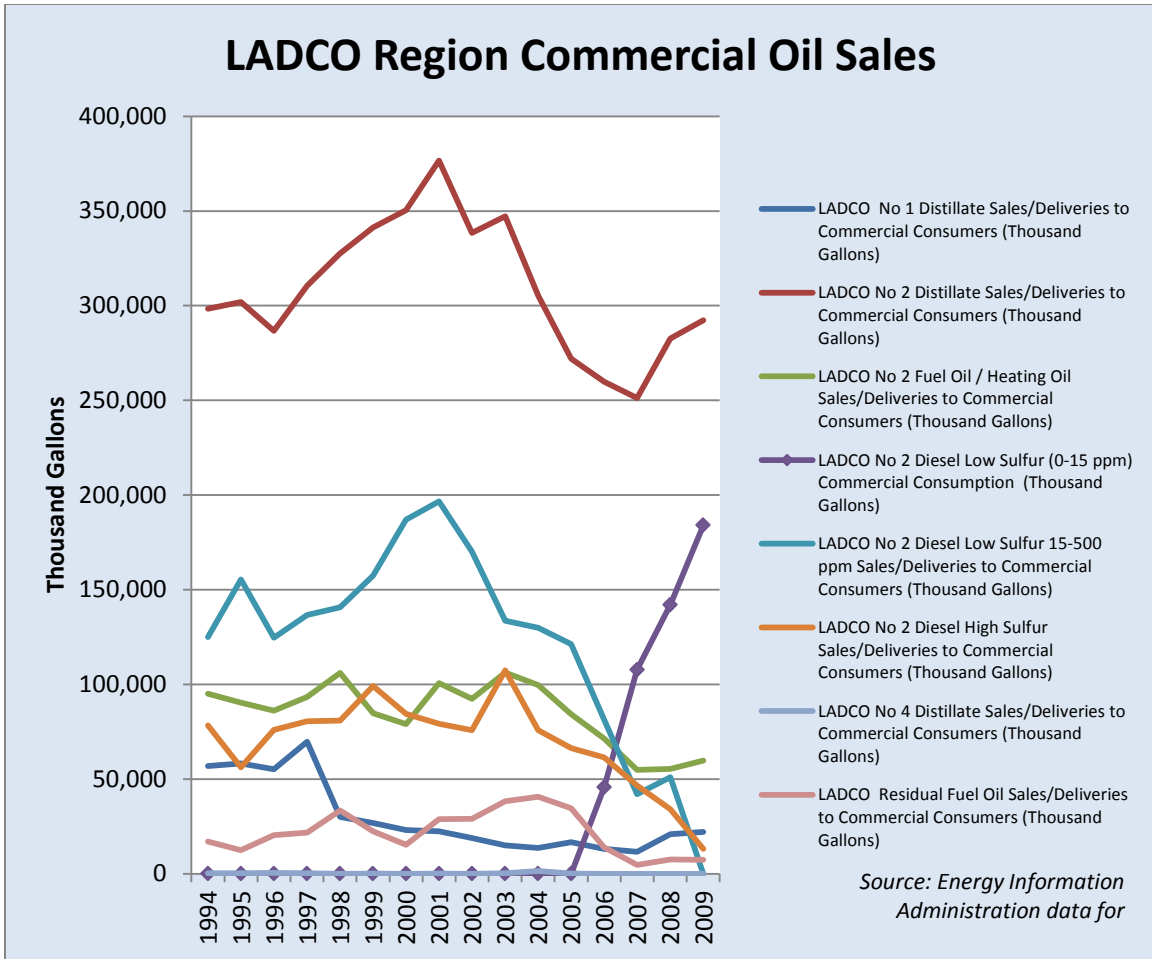
Figure 4b. Trends in Commercial Natural Gas Consumption in the LADCO region.

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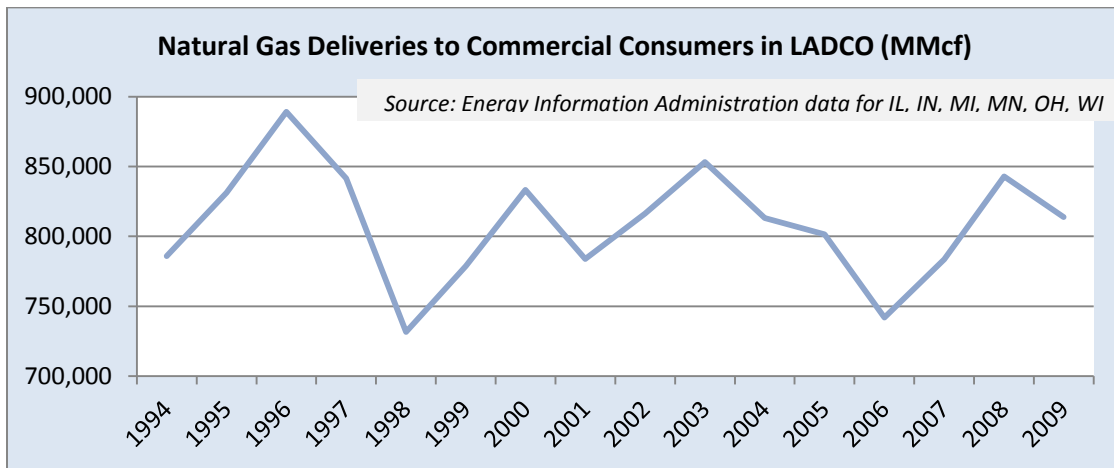**Figure 5a.** <1%S Residual Fuel Oil and >1% S Residual Fuel Oil Prices and Price Spread Developed from data, US EIA
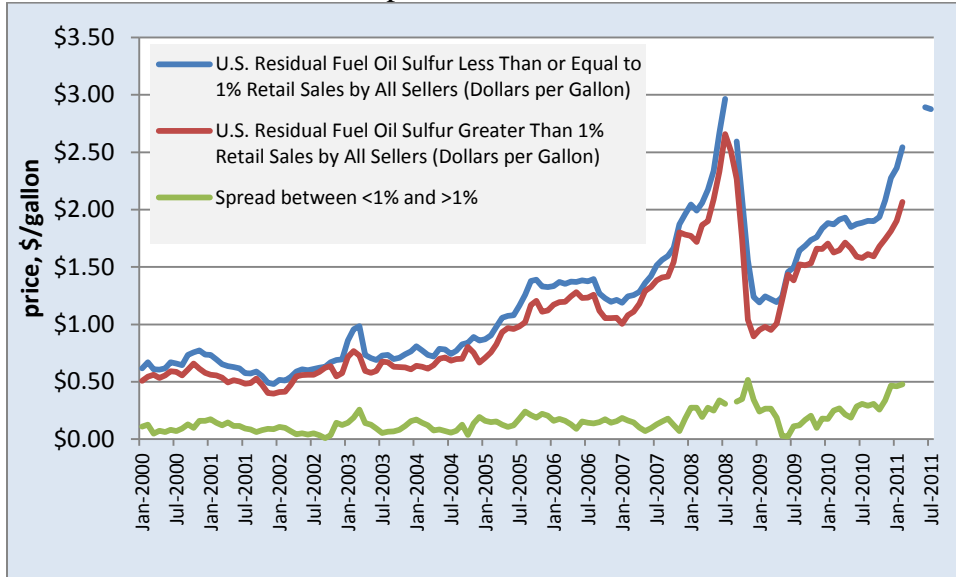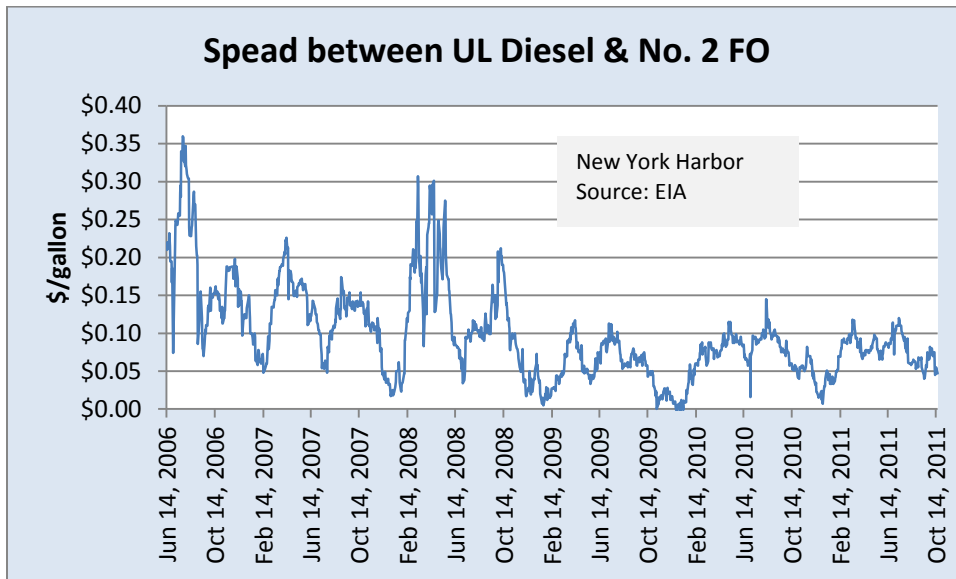

Figure 5b. Price spread between Ultra Low Diesel fuel and Number 2 Fuel Oil –NY Harbor Spot Price[a]

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[a] Data was not available for LADCO Region. So, this NY data is being used as a surrogate, assuming that similar trends would exist in the LADCO Region.

2.1.4   Cleaning of Gaseous Fuels

In the LADCO region combustion of coke oven gas (COG) and blast furnace gas (BFG) in industrial boilers is a much greater contributor to regional SO_2 emissions than combustion of oil in industrial boilers. The SO_2 emissions contribution of combustion of COG and BFC is the second largest contributor to ICI boiler SO_2 emissions after combustion of coal. These gases contain significant amounts of reduced sulfur compounds, such as H_2S. COG and BFG are manufactured gases that result from the coke-making process or the iron-making process at integrated steel mills. They are burned throughout a steel mill in different equipment – Blast Stoves, Coke Ovens, Boilers, or, if not productively burned, they are flared. In by-product coke ovens the raw volatile gas from the coke oven is cleaned and by-products such as coke oven gas (COG – a fuel), ammonia, ammonium sulfate, tar, naphthalene, benzene and other chemicals are recovered. In addition, some hazardous pollutants can be formed. However, without further desulfurization, reduced sulfur compounds remain in the fuel gas. Therefore, reduction of SO_2 emissions from combustion of these fuels can be achieved if the reduced sulfur compounds are removed from the product gases.

It is more efficient to remove sulfur from the product gaseous fuel than to capture the SO_2 in a diluted form in the exhaust gas, particularly because these product gases are burned at many different locations throughout the steel mill. Although many processes exist to clean fuel gases, they generally fall into the two categories of wet oxidation processes or absorption-stripping processes. The wet oxidation processes have the advantage of somewhat higher removal than absorption stripping but the disadvantage of producing liquid waste streams. Amine absorption-stripping processes, such as the Sulfiban process, produce high purity sulfur or sulfuric acid, and are more attractive from that standpoint. Absorption-stripping processes typically capture over 90% of the sulfur species (effectively reducing 90% of the SO_2 that would otherwise be produced) and tend to be more popular in the United States than wet oxidation processes. RTI International examined the cost of desulfurization.[9] The cost was based on an amine absorption-stripping process (such as Sulfiban) installed at US Steel's Gary, IN plant.   The cost of desulfurization was on the order of $30 million in capital and $3.5 million in operating cost (1997 dollars) on a plant producing 1.8 million tons per year of coke. The sale of product (sulfur, etc.) will mitigate this operating cost somewhat.

Other Impacts

There are other impacts of the gas cleaning technology in terms of energy usage, which may indirectly impact air emissions. For the Sulfiban Process, which is the most common process on steel plants in the US,[9] utility requirements are determined by the amine circulation rate, which is a direct function of the amount of H_2S in the COG that is being treated.[10] No other adverse impacts on air pollution are anticipated.

Although COG is the largest contributor to SO_2 emissions of the gaseous fuels, combustion of BFG also contributes a significant amount of SO_2. The low heating value of Blast Furnace Gas (typically under 100 Btu/SCF as compared to about 1000 Btu/SCF for natural gas and about 500 Btu/SCF for COG) will make cleaning BFG less economical than cleaning of COG unless a BFG gas cleaning system can be combined with a system for cleaning COG.

2.1.5 Limestone Injection for Circulating Fluid Bed (CFB) Boilers

There are several CFB boilers in the LADCO region. Unlike conventional boilers, CFBs achieve SO_2 reduction by introduction of limestone into the bed where the coal or other fuel burns. The limestone calcines in the hot bed and the free lime captures SO_2. According to Reference 11 "Although CFB boilers can achieve 98% SO_2 removal, limestone utilization is reduced as removal efficiencies exceed 90% to 95%." It is likely that some of the facilities are achieving lower than 90% SO_2 capture through limestone injection and could increase SO_2 removal somewhat. Since increasing limestone injection rate can be achieved with little or no capital expenditure, increasing limestone injection on CFB boilers can be a very cost effective approach to reducing SO_2 emissions.

2.1.6 Conversion to Natural Gas

Natural gas prices are significantly lower today than in recent years as demonstrated in Figure 6. Conversion to natural gas, or co-firing natural gas, may be a viable option for some facilities that have adequate supply of gas to their site. Natural gas will virtually eliminate SO_2 emissions and will be beneficial to emissions of other pollutants, such as NOx, mercury, and particle matter. A natural gas conversion will require modification of the burners, however, this is often much less expensive than other options such as flue gas desulfurization. Capital cost will also be impacted by the cost of any needed modifications to the natural gas supply.

Figure 6. United States Natural Gas Industrial Price
(Dollars per Thousand Cubic Feet)

Source: Energy Information Administation
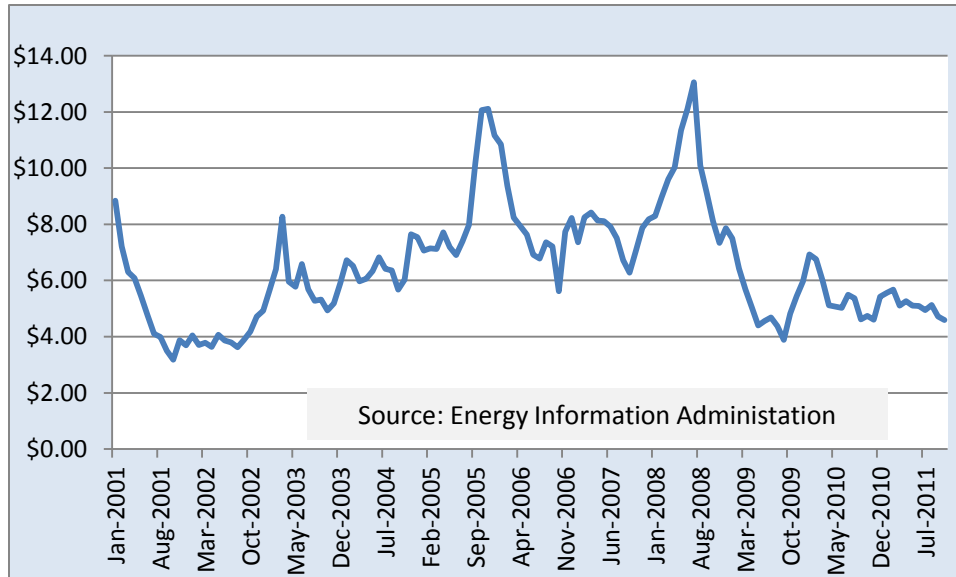
2.1.7 Regulations for ICI Boilers

LADCO's White Paper on Interim Control Measures for ICI Boilers 3/6/2006 discussed some of the regulations that have impacted the ICI Boilers, such as NSPS; PSD/NSR; State RACT Rules and settlements. Upcoming requirements that could have an impact on SO_2 emissions include the finalized Cross State Air Pollution Rule (CSAPR), regional haze rules (several boilers are BART sources), the ICI boiler MACT and the SO_2 NAAQS. CSAPR directly affects total SO_2 budgets, but is directed mostly at utility boilers. MACT regulations will likely result in some acid gas controls that will probably have some SO_2 cobenefit. LADCO and OTC have also developed draft emission limits for ICI boilers.

2.2   Portland Cement Plants

2.2.1 Inventory and Control Measures

Portland cement kilns heat up raw materials, including limestone, sand, and other materials to a high temperature to transform them into a product called clinker. The clinker is cooled and ground to a fine powder and then blended with a small amount of gypsum to make Portland Cement.

Table 7 lists the sources of SO_2 emissions from cement manufacturing in the LADCO region. Kilns are the principal source of SO_2 emissions from cement manufacturing in the LADCO region. As will be discussed below, the principal factors in determining the SO_2 emissions from a cement kiln are the properties of the raw materials and the kiln type.

Table 7. SO_2 Emissions from Cement Manufacturing in the LADCO Region

	Sum of emissions (tpy)	No. of sources
Industrial Processes - Cement Manuf	**18,515**	**20**
Cement Manuf (Dry Proc) /Kilns	10,614	9
Cement Manuf (Dry Proc) /Preheater Kiln	2,153	4
Cement Manuf (Dry Proc) /Preheater/Precalciner Kiln	2,864	1
Cement Manuf (Wet Proc) /Kilns	2,833	5
In-Process Fuel Use /Bituminous Coal /Cement Kiln/Dryer	51	1

Cement kilns are broadly divided into two types: dry process and wet process, determined by whether the raw materials are introduced into the kiln as a slurry mixed with water (wet process) or as dry, ground material (dry process). The wet process kilns are generally older and have a single, long, rotating kiln where material is introduced at one end and tumbles down to the lower end and leaves as clinker. Materials and flue gases flow in a countercurrent fashion. For the wet process kiln all of the main thermal processes – evaporation of moisture, preheating of materials, calcining of materials, and clinkering – occur along the length of the rotary kiln. The lower end of the kiln is also where the fuel is burned and is near the highest temperature point in the kiln. Dry process kilns are further divided into three types; long dry kilns, preheater kilns, and preheater/precalciner kilns (or commonly referred to as precalciner kilns). The long dry kilns are very similar to the wet kilns except that material is introduced in a dry form. The preheater kilns have a section where exhaust gases from the rotary kiln come into close contact

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with the raw materials (typically in a series of cyclone separators) dry and preheat the materials prior to introduction to the rotary kiln, which enables the rotary kiln to be shorter – calcining and clinkering occur in the rotary section. The precalciner kiln also has a precalciner in addition to the preheater, which includes a firing system where typically more than half of the fuel is burned to precalcine the limestone and other materials prior to introduction to the rotary kiln where the final, high-temperature clinkering reaction occurs.   Precalciner kilns are the most modern and efficient kilns and tend to be the largest in size. In the LADCO region, there is at least one of each of the types of kilns; however, by far, long, dry kilns are the largest in number.

SO$_2$ Formation

Although coal and petroleum coke are the most commonly used fuels for cement kilns, the SO$_2$ emissions from cement kilns are primarily from sulfur released from the raw materials rather than the fuel. This is because most of the SO$_2$ formed from fuel combustion is captured by the abundant free lime in the kiln and finds its way into the clinker product. For this reason, changing fuels is not an especially useful approach to reducing SO$_2$ emissions from Portland Cement kilns. In fact, it can be detrimental to emission of other pollutants. Changing fuel from coal to natural gas has been shown to increase NOx emissions due to the high thermal NOx generation in the kiln and the higher kiln temperature necessary when burning natural gas. For this reason, *the most effective way to reduce SO$_2$ formation from a Portland cement kiln is by changing raw materials*.

The single largest source of raw material for Portland cement is the limestone quarry that the kiln is typically situated at. For this reason there are limitations to the ability to reduce the sulfur content of the raw materials. It may be possible to find suppliers of raw materials (except for limestone) that have materials with lower sulfur content. The ability to find lower sulfur sources of material will depend upon the characteristics of the limestone near the kiln and other raw materials. Therefore, flue gas treatment has become an important method for reducing SO$_2$ emissions from those facilities that cannot economically change raw materials.

Besides the sulfur content of the raw materials, SO$_2$ emissions are influenced by the kiln type. Preheater and Precalciner kilns tend to have lower SO$_2$ emissions per ton of clinker produced than wet process or long dry kilns. As the raw materials are heated and release SO$_2$ into the exhaust gas, the exhaust gas comes into better contact with the alkaline-laden raw

materials in the preheater and precalciner. Table 7 shows the SO_2 emissions by kiln type. The long dry kilns make the highest total contribution to SO_2 emissions, and they are the largest in number. The precalciner kiln produces the highest emissions per source, but this kiln is probably much larger than the other kilns and may have lower emissions per ton of output. Figure 7 shows a plot of SO_2 Emissions in lb/ton of clinker from kilns in Portland cement market regions in and around the LADCO region as a function of kiln type and market location. As shown, for the most part long dry and wet kilns have the highest SO_2 emissions per ton of clinker. Also, there is substantial variation between markets, mainly a result of the sulfur content of local raw materials.

Figure 7. SO_2 Emissions from Cement Kilns, average by type and market region in lb SO_2/ton clinker[12]
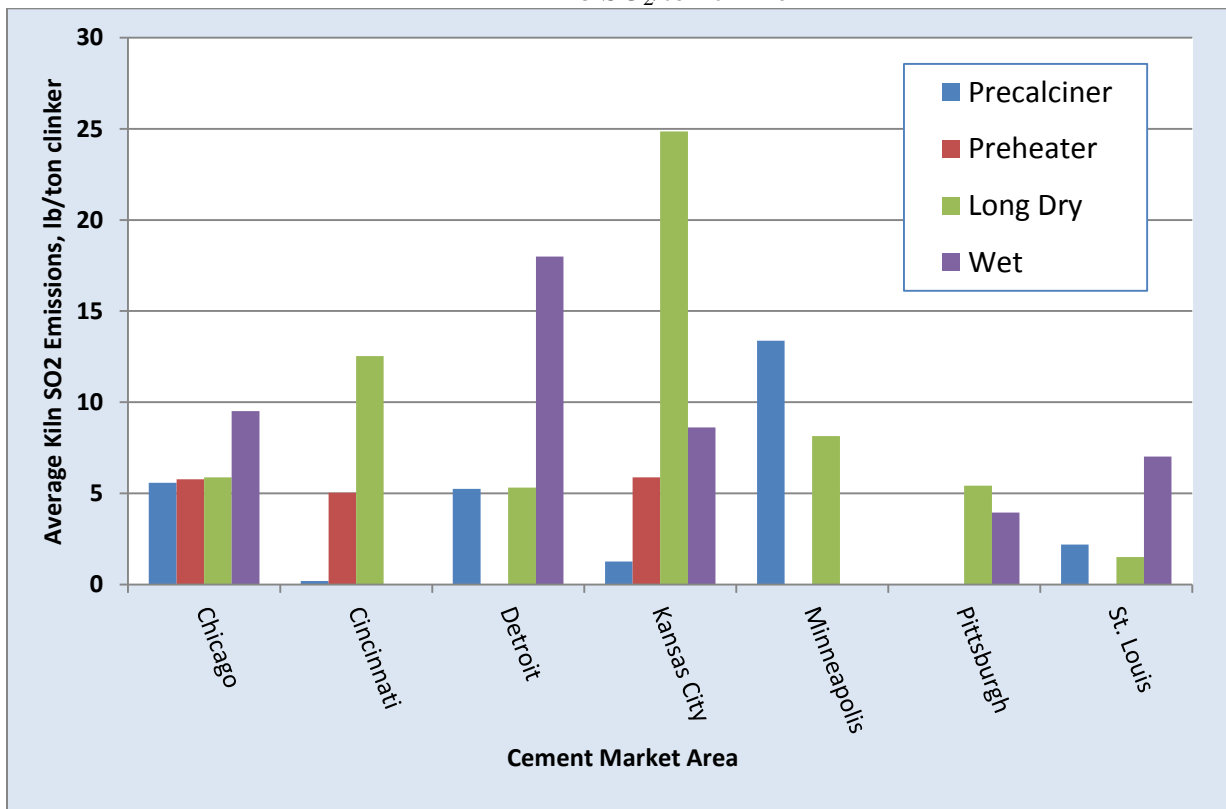
Process Changes

Process changes that can reduce SO_2 emissions include:

Conversion of long dry or wet kilns to preheater or precalciner kilns – this will likely reduce the SO_2 emissions of the kiln (in terms of lb/ton of clinker) because preheater and precalciner kilns produce lower SO_2 emissions. However, such conversions are costly and

would likely only be performed as part of a much more extensive plant upgrade program. And, even with a conversion, the SO_2 emissions may still be high because of the impact of raw materials.

In-line raw mills – that use kiln flue gas to dry and preheat the limestone and other raw materials – can provide modest reduction in SO_2 from the flue gas, especially if lime or another absorbent is introduced into the raw mill; however, most newer kilns (of the preheater or precalciner type) already utilize in-line raw mills. Per LADCO's White Paper on Interim Control Measures (3/6/2006), addition of adsorbents are estimated to reduce SO_2 by 60%-80% and at a cost of $2,031-$7,379 per ton of SO_2 removed.

Use of Steel Slag – Steel slag can be used as a raw material, if available. Since there are numerous steel mills in the LADCO region, slag should be available. Use of steel slag has the benefit of lowering sulfur emissions, lowering NOx emissions, lowering CO2 emissions and increasing kiln output. These are all possible because steel slag is very similar to clinker, requiring less energy to transform it to clinker, and it displaces other raw materials that would contribute to CO_2 and SO_2 emissions.

Flue gas treatment may be necessary for Portland Cement kilns to achieve adequate SO_2 removal. Flue gas treatment will be discussed in more detail in Chapter 3.

2.2.2 Regulations for Cement Kilns

LADCO's White Paper on Interim Control Measures for Portland Cement Kilns 3/6/2006 discussed some of the regulations that have impacted the Cement Kilns, such as NSPS, PSD/NSR, State RACT Rules and settlements. Upcoming requirements that could have an impact on SO_2 emissions include the regional haze rules (Lafarge Midwest kilns in Michigan are BART sources), the Portland Cement MACT and the SO_2 NAAQS. MACT regulations will likely result in some acid gas controls that will probably have some SO_2 cobenefit reductions.

2.3 Petroleum Refineries

2.3.1 Inventory and Control Measures

The petroleum refining industry converts crude oil into a wide variety of refined products, including fuels and feedstocks for the petrochemical industry. A refinery's equipment and operation will vary based upon the type of crude oil feedstock that it is designed to accept and the products that it is designed to produce. SO_2 emissions from refineries result from the combustion of sulfur-bearing materials. As Table 8 demonstrates, the largest source of SO_2 emissions from refineries in the LADCO region (about 2/3 of the total) is from the fluid catalytic cracking (FCC) unit(s). These SO_2 emissions result from combustion of carbon during catalyst regeneration. The carbon that is deposited on the catalyst will contain some level of sulfur that contributes to SO_2 emissions as it is burned off of the catalyst. The FCC unit will have PM controls, at least an ESP at the exit of the CO boiler, and quite possibly a PM scrubber that may already have SO_2 controls. Many facilities have already retrofit scrubbers on the FCC unit in response to US EPA's Petroleum Refinery Initiative. The SO_2 emissions reported here reflect at least some of those SO_2 emission reductions, but perhaps not all.

Process options for reducing SO_2 emissions include use of metal oxide catalysts that convert SO_2 to SO_3 inside the catalyst regenerator. The SO_3 is adsorbed to a sulfate and then recycled back to the reactor with the FCCU catalyst, where it is reduced in the reactor to H_2S, and sent to the refinery's sulfur plant. This process can remove between 20% and 60% of the SO_2 in the flue gas. This method has been shown to provide reductions at a cost effectiveness ranging from $499 - $880/ton of SO2 reduced (year 2000 dollars). [13]

Another process option is FCC feed hydrotreatment, which can significantly reduce inlet sulfur content to less than 0.1% to 0.5% by weight, depending on the initial feedstock concentration, which can in turn reduce SO_2 emissions from the FCCU catalyst regenerator by up to 90%. This process has advantages including reduction in the amount of sulfur in final refinery products, as well as improvement of final products, thereby requiring less final processing.[13]

Sulfur recovery units are used to recover sulfur from H_2S from various process units. Because of the significance of sulfur plants in the Chemicals Industry SO_2 inventory, methods from improving sulfur recovery are addressed in Section 2.6. Refinery NSPS subpart Ja requires

99% conversion for "small" sulfur recovery plants, and 99.9% conversion for large sulfur recovery plants, with 20 LTPD the dividing line between small and large sulfur plants.

There are a number of sources at the refinery that release to flares during startups, shutdowns and process upsets. An example is blowdown systems. SO_2 is released during the combustion of reduced sulfur compounds in the flares. This is best controlled by improved management of the system to avoid such conditions as well as direction of sour gas to the sulfur recovery unit; however, reduction of sulfur upstream in the process, such as hydrotreating of FCC feed, will help reduce SO_2 emissions from flares in downstream processes.

Table 8. SO_2 Emissions from Refineries in the LADCO Region (excluding boilers)

Industrial Processes - Petroleum Refineries	Sum of Emissions (tpy) 16,297	No. of sources 173
Petrol Indus /Catalytic Cracking Units /Fluid Catalytic Cracking Unit	11,146	13
Petrol Indus /Vacuum Distillate Column Condensers /Vacuum Distillation Column Condenser	1,099	2
Petrol Indus /Blowdown Systems /Blowdown System with Vapor Recovery System with Flaring	901	2
Petrol Indus /Flares /Natural Gas	797	3
Petrol Indus /Flares /Hydrogen Sulfide	532	20
Petrol Indus /Process Heaters /Process Gas-fired	424	68
Petrol Indus /Flares /Process Gas	422	8
Petrol Indus /Process Heaters /Gas-fired	412	31
Petrol Indus /Process Heaters /Oil-fired	135	5
Petrol Indus /Fugitive Emissions /Specify in Comments Field	110	2
Petrol Indus /Fugitive Emissions /Miscellaneous: Sampling/Non-Asphalt Blowing/Purging/etc.	103	2
Petrol Indus /Desulfurization /Sulfur Recovery Unit	96	4
Petrol Indus /Wastewater Treatment /Wastewater Treatment w/o Separator	34	1
Petrol Indus /Merox Treating Unit /General	31	1
Petrol Indus /Process Heaters /Landfill Gas-fired	19	3
Petrol Indus /Flares /Not Classified **	15	2
Petrol Indus /Process Heaters /Natural Gas-fired	9	3
Petrol Indus /Incinerators /Process Gas	5	1
Petrol Indus /Fugitive Emissions /Pipeline Valves and Flanges	4	1
Petrol Indus /Wastewater Treatment /Oil/Water Separator	2	1

Some process heaters burn refinery gas or other fuels that are made on site. Catalytic hydrodesulfurization is the most widely used approach for removing sulfur from product fuels, and to the extent that these fuels are burned at the refinery, catalytic hydrodesulfurization will also reduce SO_2 emissions from the refinery.

2.3.2 Regulations for Refineries

LADCO's White Paper on Interim Control Measures for Refineries 3/6/2006 discussed some of the regulations that have impacted the refineries, such as NSPS; PSD/NSR; State RACT Rules and settlements. Important progress in reducing SO_2 emissions has been achieved at LADCO refineries as a result of the US EPA's Petroleum Refinery Initiative and the inventory may not fully capture this due to the different timing in data from the states. Upcoming requirements that could have a direct or indirect impact on SO_2 emissions include the regional haze rules (several FCCU's are BART sources), future refinery MACT revisions (MACT is periodically updated) and the SO_2 NAAQS.

2.3.3 Boilers in Refining

Boilers are another source of SO_2 emissions at a refinery. These are not included in the data for Table 8 because they are included in the industrial boiler emissions. Boilers in the refining industry utilize gaseous fuels (typically refinery gas or natural gas), oil, or perhaps petroleum coke. Control methods for refinery boilers using these coals are discussed in Section 2.1.

2.4 Glassmaking facilities

2.4.1 Inventory and Control Methods

Glass manufacturing is a very energy intensive process that entails melting a mixture of raw materials, such as sand, limestone, soda ash, and cullet (scrap and recycled glass) in a furnace where a temperature is maintained in the 2,700°F to 3,100°F range. The material is drawn off in the molten state and cooled in a controlled manner to produce the final product. As shown in Table 9 melting furnaces are the largest contributors to SO_2 emissions from the glassmaking industry.

Natural gas is the preferred fuel, although other fuels and electricity may be used to heat the mixture. Cleaner fuels are preferred to assure product quality. For this reason SO_2 emissions are greatly influenced by the sulfur content of the raw materials. Since glassmaking facilities typically use clean energy sources (in terms of sulfur content), reducing sulfur content of raw materials (sand, soda ash, limestone, and cullet, or recycled glass) is an approach for reducing SO_2 emissions if a reduction in fuel sulfur (ie, lower sulfur oil, conversion to gas, or conversion to electric heating) is not possible. The principle sources of sulfur would likely be the limestone or the sand. Because these are dense materials, it is best to source them locally, and the ability of a glassmaking facility to reduce SO_2 emissions switching to lower sulfur materials will depend upon the specific sources of raw material available to a glassmaking facility. If raw material changes or fuel changes cannot be utilized to reduce SO_2 emissions, it is necessary to treat the flue gas, and treatment methods are discussed in Chapter 3.

Table 9. Sources of SO_2 emissions from Glass Manufacturing in the LADCO Region

	Sum of emissions (tpy)	No. of sources
Industrial Processes - Glass	**3,679**	**33**
Glass Manuf /Container Glass: Melting Furnace	2,108	17
Glass Manuf /Flat Glass: Melting Furnace	1,209	7
Glass Manuf /Pressed and Blown Glass: Melting Furnace	295	1
Glass Manuf /Flat Glass: Forming/Finishing	56	5
Glass Manuf /Furnace/General**	7	1
Glass Manuf /Ground Cullet Beading Furnace	2	1
Glass Manuf /Pressed and Blown Glass: Forming/Finishing	2	1

2.4.2 Regulations for Glassmaking Facilities

LADCO's White Paper on Interim Control Measures for Glassmaking Facilities 3/6/2006 discussed some of the regulations that have impacted these facilities, such as NSPS; PSD/NSR; and State RACT Rules. Fuel burning limits on SO_2 emissions apply to glass plants in Illinois,

Indiana, and Michigan. In Illinois, except furnaces in Chicago and glass treating in East St. Louis, glass plants must also comply with a 2,000-ppm process emission limit. Indiana has also established source specific limits for two plants. Plants in Ohio must comply with one of two process-weight-based curves for SO_2 emissions, depending on location, with the exception of two units in Muskingum County, which are subject to source specific limits. All glass plants in Wisconsin are subject to a 1,035 lb/hour limit for SO_2 emissions.

Upcoming requirements that could have an impact on SO_2 emissions include the regional haze rules and the SO_2 NAAQS.

2.5   Asphalt plants

2.5.1 Inventory and Control Measures

There are two industries that fall under the category of asphalt manufacture: hot mix asphalt plants (asphalt concrete) and asphalt roofing. Hot mix asphalt plants produce asphalt paving materials, while the asphalt roofing industry manufactures asphalt-saturated products for use mainly in roof construction. SO_2 emissions are from combustion of fuels (typically, oil or natural gas). Table 10 lists the sources in the asphalt industry that contribute to SO_2 emissions in the LADCO Region.   As shown, asphalt dryers and asphalt blowing are generally the largest sources of SO_2, and these are where most of the fuel is burned in these industries.

Hot mix asphalt or asphalt concrete is created by mixing and heating aggregate (which can include reclaimed asphalt pavement) with liquid asphalt cement. The heating is typically performed in a drum dryer, although some other dryer types may be used. The dryer operation is the main source of pollution at hot mix asphalt manufacturing plants. Natural gas is the preferred source of heat used by the industry, although oil, electricity and combinations of fuel and electricity are used.

SO_2 emissions from dryers can be reduced by changes in fuels consumed, use of alkaline aggregate to absorb sulfur compounds from exhaust gas, or by add-on control systems. Currently, natural gas is the fuel of choice by most asphalt manufacturers, minimizing the SO_2 emissions from fuel combustion. Low-sulfur fuel oil is an option for reducing SO_2 emissions from oil fired dryers. Alkaline aggregate (i.e., limestone) may adsorb as much as 50 percent of the sulfur compounds from the exhaust gas. The add-on control systems include both wet scrubbers and dry scrubbers. Scrubber systems remove both SO_2 and PM. The cost of using alkaline aggregate will depend upon availability of such aggregate at the location.

Asphalt roofing materials are produced through a series of steps, including asphalt preparation, followed by felt saturation, coating, mineral surfacing, cooling and drying, product finishing, and packaging. Preparation of the asphalt is done through a process called blowing, which involves bubbling air through liquid asphalt flux at high temperature for several hours in a unit called a blowing still. Asphalt blowing is the principle source of SO_2 emissions from asphalt roofing plants. SO_2 reductions can be achieved through fuel changes or through post-combustion, add-on controls.

2.5.2 Regulations for Asphalt Plants

LADCO's White Paper on Interim Control Measures for Asphalt plants 3/6/2006 discussed some of the regulations that have impacted these facilities, such as NSPS; PSD/NSR;

and State RACT Rules. Upcoming requirements that could have an impact on SO_2 emissions include regional haze rules and the SO_2 NAAQS.   In the LADCO States, asphalt manufacturing plant emissions are subject mainly to PM limits, although they may also be subject to SO_2 or NOx fuel combustion requirements depending on the size and age of the facility. Facilities may have to meet state-specific SO_2 requirements for fuel-burning equipment when burning fuel oil.

Table 10. Sources of SO_2 Emissions from Asphalt Plants in the LADCO Region

	Sum of emissions (tpy)	No. of sources
Industrial Processes - Asphalt	**596**	**103**
Asphalt Concrete /Drum Dryer: Drum Mix Plant	142	25
Asphalt Concrete /Drum Mix Plant: Rotary Drum Dryer / Mixer, #2 Oil-Fired	87	21
Asphalt Processing (Blowing) /Asphalt Blowing Still	69	1
Asphalt Roofing Manufacture /Felt Saturation: Dipping Only	46	3
Asphalt Concrete /Drum Mix Plant: Rotary Drum Dryer / Mixer, Natural Gas-Fired	42	13
Asphalt Roofing Manufacture /Asphalt Blowing: Coating	41	7
Asphalt Concrete /Batch Mix Plant: Hot Elevs, Screens, Bins&Mixer	39	8
Asphalt Concrete /Drum Mix Plant: Rotary Drum Dryer/Mixer, Waste/Drain/#6 Oil-Fired	29	3
Asphalt Concrete /Rotary Dryer: Conventional Plant	22	4
Asphalt Roofing Manufacture /Other Not Classified	21	2
Asphalt Concrete /Batch Mix Plant: Rotary Dryer, Natural Gas-Fired	15	2
Asphalt Concrete /Batch Mix Plant: Hot Elevators, Screens, Bins, Mixer & NG Rot Dryer	9	3
Asphalt Concrete /Batch Mix Plant: Hot Elevators, Screens, Bins, Mixer& #2 Oil Rot Dryer	8	1
Asphalt Concrete /Drum Mix Pl: Rotary Drum Dryer/Mixer, Waste/Drain/#6 Oil, Counterflow	6	1
Asphalt Roofing Manufacture /Fixed Roof Tank: Working Loss	5	2
Asphalt Concrete /Batch Mix Plant: Hot Elevs, Scrns, Bins, Mixer& Waste/Drain/#6 Oil Rot	3	1
Asphalt Concrete /Drum Mix Plant: Rotary Drum Dryer / Mixer, #2 Oil-Fired, Parallel Flow	3	1
Asphalt Concrete /Batch Mix Plant: Rotary Dryer, Oil-Fired (also see -46)	2	1
Asphalt Roofing Manufacture /Shingles and Rolls: Coating	2	1
Asphalt Concrete /Asphalt Heater: Distillate Oil	1	1
Asphalt Concrete /Asphalt Heater: Natural Gas	1	1
Asphalt Concrete /Asphalt Heater: Waste Oil	1	1

2.6 Chemical plants

2.6.1 Inventory and Control Measures

Chemical manufacturing includes a wide range of processes; however, as shown in Table 11, the largest chemical manufacturing sources of SO_2 emissions in the LADCO region are associated with Carbon Black manufacturing, Sulfur plants, sulfuric acid production, or phthalic anhydride production.

Carbon black is produced by thermal decomposition of oil or natural gas, under very well controlled conditions. There are two processes, the Furnace Black and the Thermal Black processes, and the Thermal Black process is the type used in this case in the LADCO region. The feedstock for the thermal black process is either natural gas or heavy aromatic oils. Two furnaces alternate between preheating and carbon production. The feedstock is injected into the hot furnace and decomposes the feed into carbon black and hydrogen. The stream is quenched with water and filtered in a baghouse. The exiting carbon black may be further processed to remove impurities, pelletized, screened, and then packaged for shipment. The hydrogen off-gas is burned in air to preheat the second furnace.[14] Sulfur in the feedstock may produce reduced sulfur compounds during thermal decomposition and these reduced sulfur compounds contribute to SO_2 emissions. If heavy aromatic oils are used as the feedstock, conversion to natural gas is a way to reduce SO_2 emissions.

Sulfur plants used at chemical plants and in refineries produce sulfur using the modified Claus process, which converts H_2S to liquid sulfur in a catalytic reaction. The H_2S is first captured from the gas stream through an amine solvent process and then fed to the Claus unit. The first step of the Claus unit is partial oxidation of the H_2S to H_2S and SO_2 at a high temperature (over 1000°C). The H_2S and SO_2 are then fed to catalytic reactors at lower temperature (200-350°C) to produce sulfur, SO_2 and water. There are typically multiple stages of the catalytic reactors to achieve H_2S conversion rates in the 90%+ range. SO_2 is an inevitable by-product of this process, without modification of the Claus process to improve sulfur yield, further SO_2 reduction is only possible through use of tail gas systems or exhaust gas treatment.

There are several processes available that extend the Claus reaction into a lower temperature liquid phase. These processes take advantage of the enhanced Claus conversion at

cooler temperatures in the catalytic stages. All of these processes give higher overall sulfur recoveries of 98 to 99 percent when following downstream of a typical 2- or 3-stage Claus sulfur recovery unit, and therefore reduce SO_2 emissions, but this is inadequate for achieving NSPS requirements.

Sulfur emissions can also be reduced by adding a scrubber at the tail end of the plant. There are essentially 2 generic types of tailgas scrubbing processes: oxidation tailgas scrubbers and reduction tailgas scrubbers. The first scrubbing process is used to scrub SO_2 from incinerated tailgas and recycle the concentrated SO_2 stream back to the Claus process for conversion to elemental sulfur. The Wellman-Lord process is one example of this approach that uses a wet generative process to reduce stack gas sulfur dioxide concentration to less than 250 ppmv and can achieve approximately 99.9 percent sulfur recovery.

In the second type of scrubbing process, sulfur in the tailgas is converted to H_2S by hydrogenation in a reduction step. After hydrogenation, the tailgas is cooled and water is removed. Although other processes exist, the most common utilize conventional amine scrubbing and regeneration to remove H_2S and recycle back as Claus feed, also improving sulfur recovery.[15]

Sulfuric acid is produced either by the Contact process or the Wet Sulfuric Acid process. In either process sulfur or H_2S are oxidized to form SO_2, passed over a V_2O_5 catalyst to convert the SO_2 to SO_3. In the contact process (what is used in the LADCO region) the SO_3 is absorbed to a sulfuric acid fume and then diluted to sulfuric acid. Process modifications to improve yield of sulfuric acid will reduce SO_2 emissions; however, manufacturers have likely pursued methods to improve conversion. For this reason, gas cleaning methods are likely to be necessary for further reductions.

Phthalic Anhydride is a chemical used as a plasticizer and is produced by oxidation of o-xylene. o-xylene is oxidized with an excess of air over catalysts to produce the phthalic anhydride. The process itself does not produce SO_2 emissions, but the heating of the material does when sulfur-bearing fuel is burned. As a result, SO_2 emissions from this process may be reduced through changing to lower sulfur fuels (ie., oil to lower sulfur oil or to natural gas).

2.6.2 Regulations for Chemical Plants

LADCO's White Paper on Interim Control Measures for Chemical plants 3/6/2006 discussed some of the regulations that have impacted these facilities, such as NSPS; PSD/NSR, State Rules and LADCO rules. Process SO_2 emission sources in Ohio with 1,000 pounds/hour and greater process throughput must comply with one of two process-weight-based curves dependent on location. No other MPRO state has adopted an across-the-board limitation for process SO_2 emissions. Illinois, Michigan and Ohio have specific limits for SO_2 emissions from sulfuric acid plants. The Illinois and Michigan limits are 4 and 0.5 lbs SO_2 per ton of 100% acid produced, respectively. Ohio has established plant specific limits for sulfuric acid plant emissions for three different facilities at 6.5, 25, and 35 lbs SO_2 per ton of 100% acid produced.

Chemical plants are also subject to MACT standards that may indirectly impact SO_2 emissions. Upcoming requirements that could have an impact on SO_2 emissions include the regional haze rules and the SO_2 NAAQS.

2.6.3 Boilers in the Chemical Industry

Chemical plants may also utilize boilers for the purpose of generating process steam. Typical fuels are fuel oil or natural gas. For methods to control SO_2 emissions from these boilers, see Section 2.1.

Table 11. SO$_2$ Emissions from Chemical Manufacturing in the LADCO Region (excluding boilers)

Industrial Processes - Chemical Manuf	Sum of emissions (tpy)	No. of sources
	8,975	67
Chem Manuf /Carbon Black Prod /Thermal Process	1,772	1
Chem Manuf /Elemental Sulfur Production /Mod. Claus: 3 Stage w/o Control (95-96% Removal)	1,244	2
Chem Manuf /Sulfuric Acid (Contact Process) /Absorber/@ 99.5% Conversion	1,175	1
Chem Manuf /Sulfuric Acid (Contact Process) /Absorber/@ 99.0% Conversion	1,098	1
Chem Manuf /Carbon Black Prod /Pellet Dryer	716	1
Chem Manuf /Phthalic Anhydride /o-Xylene Oxidation: Main Process Stream	526	1
Chem Manuf /Plastics Production /Others Not Specified	500	1
Chem Manuf /Elemental Sulfur Production /Mod. Claus: 2 Stage w/o Control (92-95% Removal)	406	7
Chem Manuf /Fuel Fired Equipment /Natural Gas: Flares	367	2
Chem Manuf /Sulfuric Acid (Contact Process) /Other Not Classified	320	1
Chem Manuf /Other Not Classified /Specify in Comments Field	278	14
Chem Manuf /Elemental Sulfur Production /Sulfur Removal Process (99.9% Removal)	186	5
Chem Manuf /Fuel Fired Equipment /Specify in Comments Field	174	4
Chem Manuf /Ethylene Glycol /General	32	1
Chem Manuf /Methanol-Alcohol Production /Other Not Classified	26	2
Chem Manuf /Fuel Fired Equipment /Natural Gas: Process Heaters	25	2
Chem Manuf /Inorganic Pigments /TiO2 Chloride Process: Reactor	24	1
Chem Manuf /Chlorine /Carbon Reactivation	21	1
Chem Manuf /Wastewater Treatment /Wastewater Treatment	18	2
Chem Manuf /Fuel Fired Equipment /Natural Gas: Incinerators	16	2
Chem Manuf /Methanol-Alcohol Production /Ethanol by Fermentation	15	2
Hydrazine, Olin Raschig Process /Process Vents: Chloramine Reactor	8	2
Chem Manuf /Explosives TNT /Continuous Process: Sulfuric Acid Concentrators	6	1
Chem Manuf /Wastewater Treatment /Wastewater Stripper	6	1
Chem Manuf /General Processes /Air Oxidation Units	4	1
Chem Manuf /Fuel Fired Equipment /Distillate Oil (No. 2): Process Heaters	4	3
Chem Manuf /Plastics Production /Blowing Agent: Freon (Polyether Resins)	3	2
Chem Manuf /Nitriles, Acrylonitrile, Adiponitrile /Absorber Vent: Normal	1	1
Chem Manuf /Ammonia Production /Primary Reformer: Natural Gas Fired	1	1

2.7 Cokemaking facilities

2.7.1 Inventory and Control Measures

Coke is used in blast furnaces to convert ore to iron ("hot metal" or "pig iron"). Coke is produced from the heating of coal to drive off the volatile species in the coal to produce a highly carbonaceous product – coke. In the by-product coke-making process, the raw, volatile gas from the coke oven is cleaned and by-products such as coke oven gas (COG – a fuel), ammonia, ammonium sulfate, tar, naphthalene, benzene and other chemicals are recovered. In addition, some hazardous pollutants can be formed. However, without further desulfurization, reduced sulfur compounds remain in the COG. The COG is the principle fuel for the coke ovens and also is used in other locations in the steel mill where combustion of COG will emit SO_2. SO_2 is also released from leaks in the coke ovens.

Table 12 details SO_2 emission sources from by-product coke facilities. Most is associated with the by-product plant, the combustion stack or from coke oven underfiring, which entails the combustion of COG.

Lower sulfur coal is preferred for iron production as well as low concentration of reduced sulfur compounds in COG. So, facilities will generally buy the lowest sulfur coal that has the right qualities for coke production. As discussed in Section 2.1.4, SO_2 emissions from COG combustion may controlled initially by removing the reduced sulfur compounds from the COG prior to combustion. After reducing the content of reduced sulfur compounds in the COG, or use of lower sulfur coking coal, flue gas treatment is the next option for reducing SO_2 emissions from by-product coke facilities.

2.7.2 Regulations for Cokemaking Facilities

There is no LADCO White Paper for Cokemaking factilities; however they are subject to NSPS; PSD/NSR and State Rules. Cokemaking plants are also subject to MACT standards that may indirectly impact SO_2 emissions. Upcoming requirements that could have an impact on SO_2 emissions include the regional haze rules and the SO_2 NAAQS.

2.7.3 Boilers used at Cokemaking Facilities

By product coke making facilities generate COG that is utilized productively in boilers or other facilities. Control of SO_2 from boilers utilizing these fuels is discussed in Section 2.1.

Table 12. SO$_2$ Emissions from by-product coke facilities

Industrial Processes - By-product Coke Manuf	16,517	30
By-product Coke Manuf /Gas By-product Plant	5,498	2
By-product Coke Manuf /Combustion Stack: Coke Oven Gas (COG)	5,130	6
By-product Coke Manuf /Oven Underfiring	2,257	2
By-product Coke Manuf /Topside Leaks	1,859	2
By-product Coke Manuf /Not Classified **	1,424	2
By-product Coke Manuf /Oven Pushing	214	11
By-product Coke Manuf /Quenching	108	2
By-product Coke Manuf /Combustion Stack: Blast Furnace Gas (BFG)	18	1
By-product Coke Manuf /Oven Charging	6	1
By-product Coke Manuf /Coal Preheater	4	1

2.8   Lime kilns

2.8.1 Inventory and Control Measures

Lime is produced by the calcination of limestone in a kiln. Twenty five of the twenty eight lime kilns in the LADCO region are rotary kilns. Three kilns are vertical kilns. SO_2 emissions are from fuel combustion as well as from sulfur in the raw material (limestone) In fact, gas fired kilns are relatively high emitters of SO_2, as shown in Table 13, demonstrating the importance of raw material sulfur content on SO_2 emissions.

SO_2 emissions from lime kilns can be controlled by using lower sulfur limestone; however, this is limited by the available limestone, which must be sourced locally (ideally the kiln is located on or near a quarry). Since options to reduce raw material sulfur are usually limited, post combustion controls may be necessary to reduce SO_2 emissions. Because the lime kiln produces its own lime and typically has PM emissions controls, post-combustion SO_2 controls may be very cost effective. Since the lime kiln would have PM control, SO_2 control may be possible at a moderate cost, as will be discussed in the last section of this report.

2.8.2 Regulations for Lime Kilns

There is no LADCO White Paper for lime kilns; however they are subject to NSPS; PSD/NSR and State Rules. Upcoming requirements that could have an impact on SO_2 emissions include the regional haze rules and the SO_2 NAAQS.

Table 13. SO_2 Emissions from Lime Kilns

	Sum of emissions (tpy)	No. of sources
Industrial Processes - Lime Manuf /Calcining	**16,270**	**28**
Lime Manuf /Calcining: Rotary Kiln **	7,188	11
Lime Manuf /Calcining: Gas-fired Rotary Kiln	6,913	2
Lime Manuf /Calcining: Coal-fired Rotary Kiln	1,700	6
Lime Manuf /Calcining: Vertical Kiln	247	3
Lime Manuf /Calcining: Coal- and Gas-fired Rotary Kiln	210	5
Lime Manuf /Calcining: Coal- and Coke-fired Rotary Kiln	13	1

2.9   Brickmaking facilities

2.9.1 Inventory and Control Measures

As shown in Table 14, SO_2 emissions from brickmaking are primarily from kilns used to fire the bricks. These kilns will fire the brick in a batch process for a period lasting at least several hours. Several kiln types exist, but tunnel kilns are the most common in the LADCO Region.

Fuels used include coal, oil and gas, and in some cases electricity. As shown, even gas-fired kilns emit significant SO_2, this is because much of the SO_2 is from oxidation of sulfur in the raw materials. Options to reduce SO_2 emissions from these kilns include conversion to electric heating, reducing sulfur of fuel, reducing sulfur content of raw materials, or flue gas controls. Since most kilns are gas fired (presumably natural gas), a reduction of fuel sulfur content is not an option, and it is likely that a large portion of the SO_2 emissions are from raw materials rather than fuel. In these cases a change in raw materials to lower sulfur content, or perhaps addition of more alkaline materials (such as limestone or lime) will help reduce the SO_2 emissions of the kiln; however, this must be done with consideration to material cost and maintaining product quality. For this reason, use of these methods will be very site and product specific, and in some cases exhaust gas treatment will be preferred.

Tunnel kilns generally do not have PM emission controls, but some kilns use sodium based wet scrubbers for HF control.[16]   If such a wet scrubber exists, it may be possible to also utilize it for SO_2 control.

2.9.2 Regulations for Lime Kilns

There is no LADCO White Paper for brick manufacturing; however they are subject to NSPS; PSD/NSR and State Rules. Upcoming requirements that could have an impact on SO_2 emissions include the regional haze rules and the SO_2 NAAQS.

Table 14. SO$_2$ Emissions from Brickmaking

Industrial Processes - Brick	Sum of emissions (tpy)	No. of sources
Industrial Processes - Brick	**1,546**	**9**
Brick Manuf /Curing and Firing: Gas-fired Tunnel Kilns	1,151	4
Brick Manuf /Curing and Firing: Gas-fired Periodic Kilns	263	1
Brick Manuf /Curing and Firing: Dual Fuel Fired Tunnel Kiln	82	1
Brick Manuf /Curing and Firing: Coal-fired Periodic Kilns	23	1
Brick Manuf /Curing **	18	1
Brick Manuf /Curing and Firing: Coal-fired Tunnel Kilns	9	1

2.10   Pulp and paper mills

2.10.1 Inventory and Control Measures

Manufacture of paper involves the following three steps.

- Wood preparation – In this step the wood bark is removed and the trees cut into chips that can be fed into the Pulping process.
- Pulping – Pulping is the process of reducing wood (or other cellulosic fiber source) into a fibrous mass suitable for papermaking. The process involves breaking the chemical bonds of the raw material through mechanical and/or chemical means in order to liberate the discrete fibers used to make paper. Once the fibers are separated, they are screened, washed to varying degrees, thickened, and sent to pulp storage.
- Paper Making – In this step the pulp is pressed, dried and finished into usable paper product.

The most widely used process for manufacturing pulp is the Kraft process. It is an energy-intensive chemical process that utilizes sodium sulfide and sodium hydroxide to chemically break the chemical bonds that hold the cellulosic fiber together. The Kraft process utilizes chemical recovery furnaces and lime kilns to recover and reutilize chemical reagents in the process. Fossil fuel boilers that provide process steam and power are the largest sources of SO_2 emissions at pulp and paper mills.

As shown in Table 15, after the power boilers the most significant SO_2 emissions sources are the recovery furnaces, contributing over 90% of the remainder of the SO_2 emissions from pulp and paper mills after emissions from power boilers are excluded.

Recovery furnaces burn off the organic components of the concentrated black liquor and recover the inorganic chemicals used in the pulping process. These chemicals, when collected on the floor of the recovery furnace, are referred to as smelt. The principal objective is to convert sodium sulfate in the black liquor to sodium sulfide for use in the pulping process. Recovery furnaces generally use oil or gas for startup and shutdown, but otherwise primarily burn black liquor. Prior to combustion in the recovery furnace, black liquor is concentrated through evaporators, which reduce the moisture concentration of the black liquor to a typical range of about 25%-35%, increasing black liquor solids (BLS) concentrations to 65%-75%. Higher BLS concentrations will result in lower demand for fossil fuels and improved efficiency. Evaporators may be of the direct contact type (where exhaust gases come directly in contact with black liquor) or the indirect type (where exhaust gases heat the black liquor through a heat

exchange medium). Indirect type evaporators are generally preferred due to the lower emissions of reduced sulfur compounds and other pollutants, and are the type used in LADCO Region recovery boilers.

Table 15. SO_2 Emissions from Pulp & Paper Industry Sources (excluding boilers)

	Sum of emissions (tpy)	No. of sources
Industrial Processes - Pulp & Paper	**5,795**	**56**
Sulfate (Kraft) Pulping /Recovery Furnace/Indirect Contact Evaporator	5,434	13
Sulfate (Kraft) Pulping /Lime Kiln	103	11
Sulfate (Kraft) Pulping /Smelt Dissolving Tank	65	8
Neutral Sulfite Semichemical Pulping /Digester/Blow Pit/Dump Tank	41	1
Pulp&Paper&Wood /Fugitive Emissions /Specify in Comments Field	39	7
Sulfite Pulping /Digester/Blow Pit/Dump Tank: Calcium	37	1
Sulfite Pulping /Acid Plant: Ca	26	3
Oriented Strandboard Manuf /Hot Press, Phenol-Formaldehyde Resin	11	3
Sulfate (Kraft) Pulping /Brown Stock Washing System	8	1
Neutral Sulfite Semichemical Pulping /Fluid Bed Reactor	7	2
Oriented Strandboard Manuf /Hot Press, PF Resin (surface layers) / MDI Resin (core layers)	6	1
Sulfite Pulping /Knotters/Washers/Screens/etc.	5	1
Sulfate (Kraft) Pulping /Recovery Furnace/Direct Contact Evaporator	5	1
Plywood Operations /Waferboard Dryer (See 3-07-010 For More Detailed OSB SCCs)	3	1
Plywood Operations /Hardboard: Core Dryer	2	1
Oriented Strandboard Manuf /Direct Wood-fired Rotary Dryer, Aspen	2	1

As shown in Figure 8, SO_2 emissions from recovery furnaces have been shown to be related to the sulfidity of the smelt, or the percent of the smelt that is sodium sulfide (versus sodium carbonate or sodium hydroxide). Sufficiently low sulfidity (in this case below 28%) will yield very low SO2 emissions. Increased smelt sulfidity may therefore be associated with increased SO2 emissions. [17]
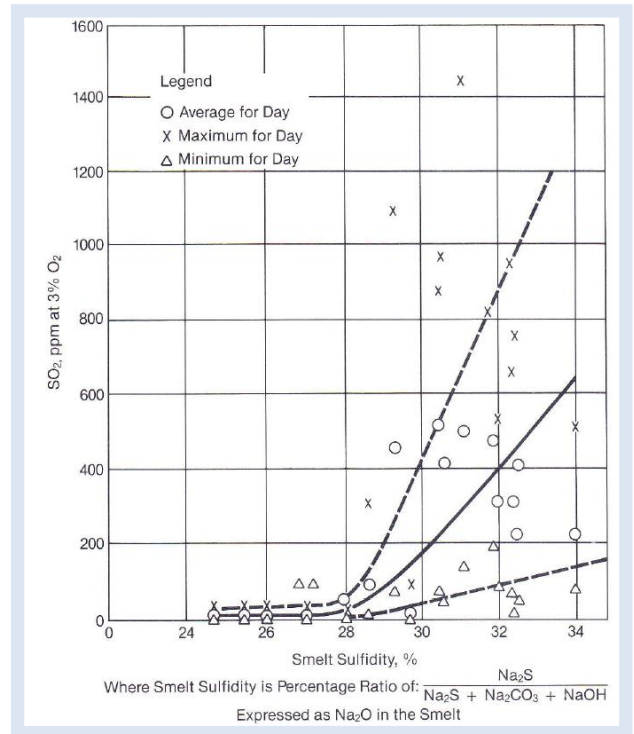
Since the role of the recovery furnace is to recover sodium sulfide from the black liquor, ability to control SO_2 in the recovery furnace may be limited in light of the need to recover sodium sulfide. Therefore, to the extent that SO_2 emissions from the recovery furnace cannot be further reduced, it may be necessary to add flue gas treatment. Recovery furnaces typically have ESPs for PM control.

Figure 8. Effect of smelt sulfidity on SO_2 emissions [14]

The lime kiln is used to produce lime for use in the causticizing reaction that converts green liquor (what is produced from the smelt from the recovery boiler) to white liquor (what is mixed and cooked with the wood chips). Lime kilns at pulp mills often have wet PM scrubbers, which may make them amenable to SO_2 controls. Controls for lime kilns are discussed in Section 2.9.

2.10.2 Regulations for Pulp and Paper Mills

There is no LADCO White Paper for pulp and paper mills; however they are subject to NSPS; PSD/NSR and State Rules. Upcoming requirements that could have an impact on SO_2 emissions include the regional haze rules, the Pulp and Paper MACT and the SO_2 NAAQS.

2.10.3 Boilers at Pulp and Paper Mills

Both the pulping and papermaking processes use large amounts of process steam and power, and power boilers that fire hog fuel (wood waste) and fossil fuels provide steam and power beyond what is provided by the recovery furnaces. The largest sources of SO_2 emissions from pulp mills and paper mills are typically the power boilers that generate power and steam at the mills, especially those boilers that fire coal or heavy oil, and these are included in the SO_2 emissions described in Section 2.1. Although biofuels, which are generally low in SO_2 emissions are used at pulp and paper mills, fossil fuel (most often coal) is used to provide for the additional steam and power needs that are not adequately met with biofuels, and these fuels result in most of the SO_2 emissions from pulp and paper mills. Information on how to control SO_2 from these boilers is contained in Section 2.1.

2.11   Iron and Steelmaking facilities, including Taconite plants

2.11.1 Inventory and Control Measures

Iron and Steelmaking occur at integrated mills, which convert ore into iron and iron into steel, typically used blast furnaces and the basic oxygen process, and mini mills, which typically convert recycled steel scrap into steel, typically using electric arc furnaces. Integrated steel mills utilize iron ore, and virtually all of the domestic iron ore is from taconite plants in Minnesota (the Mesabi iron ore deposits) and Michigan (the Marquette iron ore deposits). The LADCO region has a high concentration of integrated steel mills and taconite plants, as depicted in Figure 9, which shows the location of integrated steel mills and taconite plants in the United States. [b]

Figure 9. Location of integrated steel mills (blue) and taconite plants (red) in the United States.[18]
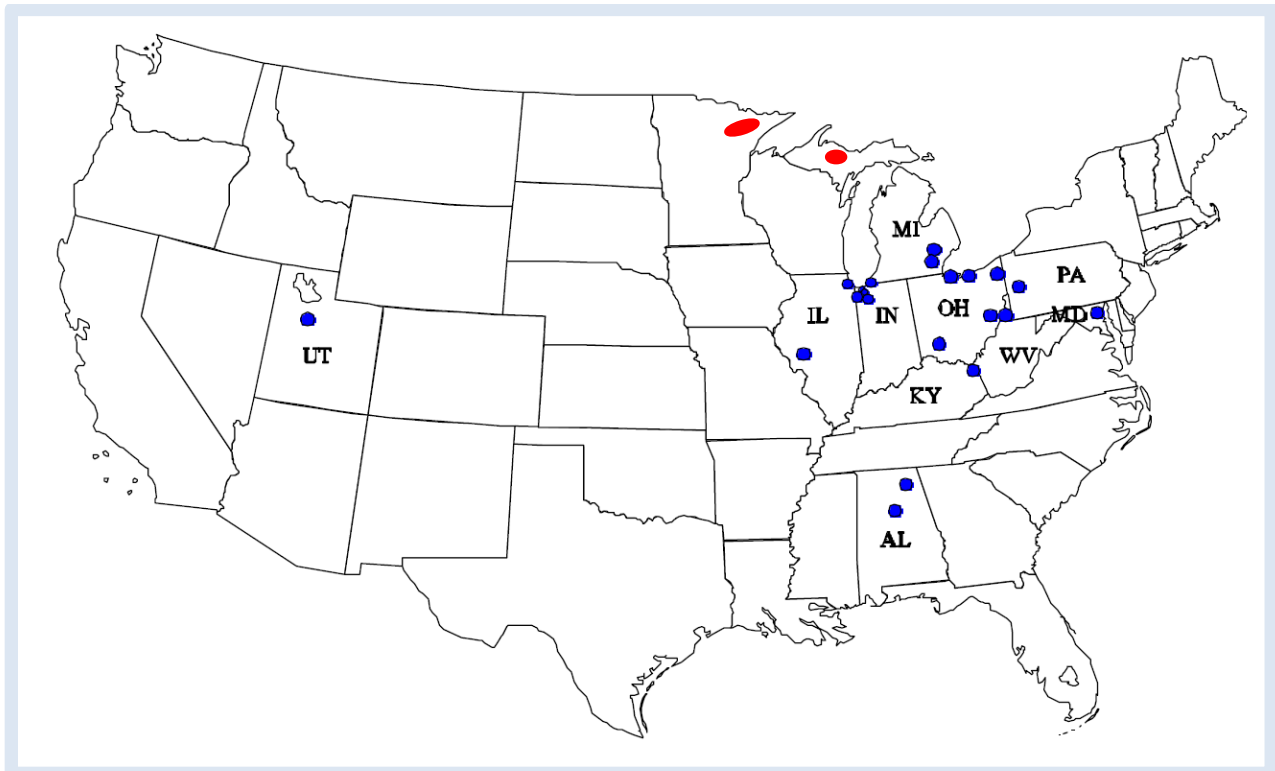
Table 16 details the SO_2 emissions from the ferrous metals industry (this does not include industrial boilers or the coke-making process, which are addressed in Sections 2.1 and 2.6, respectively).

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[b] Due to the increased demand for iron ore, some low grade sources of ore may be opening in some other states.

Nineteen ironmaking cast houses are collectively the largest individual source category with regard to total SO_2 emissions. Other aspects of the ironmaking process or the blast furnace are also significant SO_2 sources. According to AP-42, "Casting emissions at existing blast furnaces are controlled by evacuation through retrofitted capture hoods to a gas cleaner, or by suppression techniques. Emissions controlled by hoods and an evacuation system are usually vented to a baghouse. The basic concept of suppression techniques is to prevent the formation of pollutants by excluding ambient air contact with the molten surfaces." [19] To the extent that suppression techniques cannot produce adequate reductions in emissions of SO_2, gas treatment methods are necessary.

Although the nineteen cast houses produce significant SO_2 emissions in total, taconite plants (and especially induration kilns) are the largest individual sources of SO_2 emissions in the LADCO region ferrous metals category. Taconite is low-grade iron ore that is used to make iron-bearing pellets used in blast furnaces to produce iron. To make the pellets the taconite ore is first crushed and processed. Taconite fines are pelletized to make "green" pellets that are course enough for feeding to the blast furnace. The pellets are classified as acid pellets or flux pellets depending upon whether or not a fluxing agent (limestone) is added to the taconite fines and binder to form the pellets. The green pellets, which are too weak in mechanical strength for feeding to a blast furnace, are then fired in the induration furnace, which fuses and hardens the pellets.

The induration furnaces that are the largest sources of SO_2 are of the grate/kiln type. A grate-kiln-cooler system is shown in Figure 10. These use a first firing step of a continuously moving grate, onto which a bed of green pellets is deposited. The grate passes through a firing zone of alternating up and down currents of heated gas. The pellets then pass into a rotary kiln and then into a separate cooler that cools the pellets by preheating air. It is a continuous process.

The SO_2 from induration furnaces originates from sulfur in the fuel and from sulfur in the raw materials. Flux pellets will emit lower SO_2 originating from sulfur in the raw materials due to some SO_2 capture from the limestone flux. Table 16 shows that induration furnaces firing acid pellets emit significantly higher SO_2 emissions than induration furnaces firing flux pellets. Induration furnaces frequently have wet scrubbers for PM emissions control [19](the taconite plants in Minnesota have wet PM scrubbers that may provide modest SO_2 reductions, however it is not

known if the other units in the LADCO region have wet PM scrubbers or ESPs as shown in Figure 10).

Other important sources of SO_2 emissions from the ferrous metals industry include electric arc furnaces (EAFs) and smelting furnaces. EAFs produce steel from mostly recycled steel, other iron-bearing materials, and lime as a fluxing agent, with heat added with high temperature electrodes and natural-gas oxy-fuel burners. Sulfur in the feed materials will oxidize to form SO2 when making steel in an EAF. The SO_2 will be captured in part by the lime that will contribute to a slag that forms at the top of the EAF. Like EAFs, ferrosilicon smelting furnaces heat the material with electrodes; however, in this case the feed is iron-bearing material, silicon, a reducing agent and fluxing agent and the product is typically ferrosilicon ingots. EAF emissions are collected and sent to fabric filters.[20] Ferroalloy smelting furnaces have PM controls, frequently fabric filters or wet scrubbers, and in some cases ESPs.[21]

Figure 10. A Grate-Kiln- Cooler Indurating Furnace general arrangement [22]
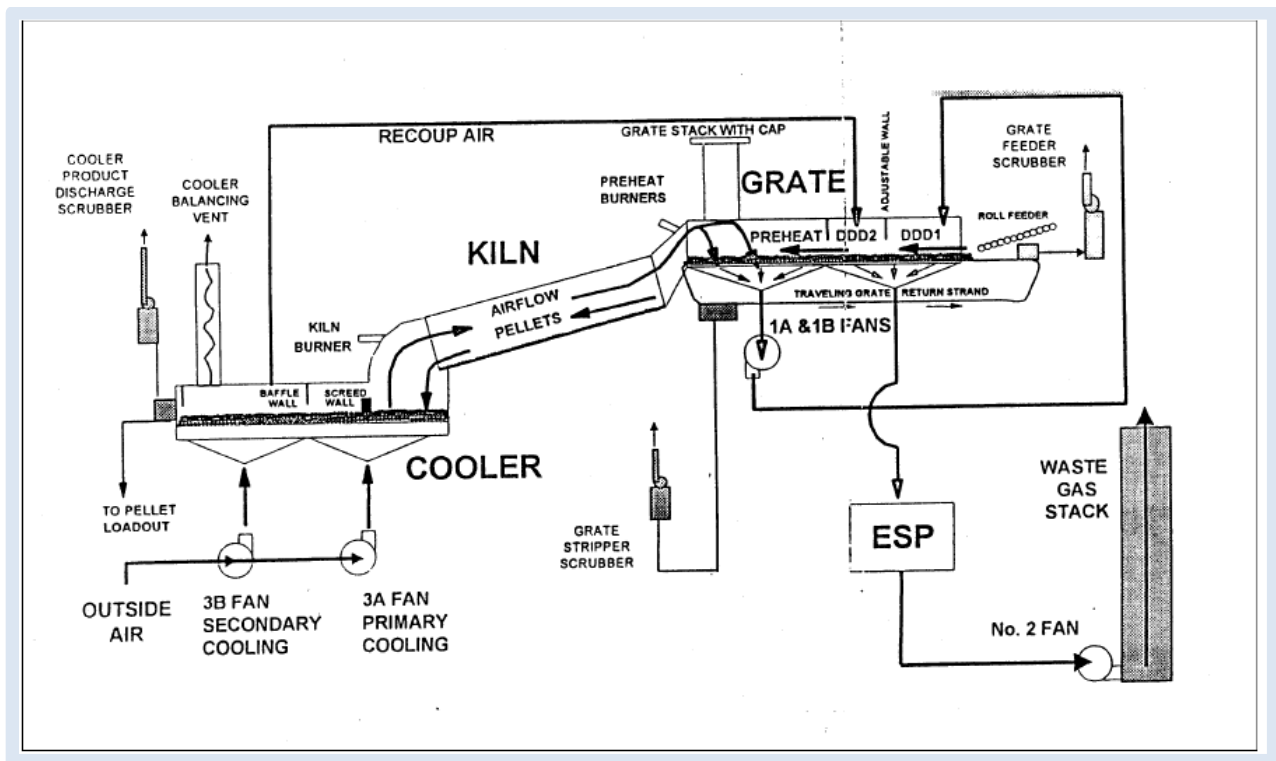
Two sinter line windboxes contribute 755 ton per year of SO_2. These windboxes are associated with the sinter line, which prepares iron ore that has not already been prepared at, for

example, a taconite plant for use in the blast furnace. The sinter line windbox PM emissions are typically controlled with either a baghouse or a PM scrubber. [23]

Because all of these sources in the iron and steel industry have PM emissions controls, it may be possible to integrate an SO_2 capture system into the PM emissions control system at a relatively low cost, and this is discussed in Section 3.4.4.

2.11.2 Regulations for Iron and Steel Mills and Taconite Plants

There is no LADCO White Paper for Iron and Steel Mills or Taconite Plants; however they are subject to NSPS; PSD/NSR and State Rules. Upcoming requirements that could have an impact on SO_2 emissions include the regional haze rules (all of the taconite plants are subject to BART), the Iron and Steel MACT and the SO_2 NAAQS.

2.11.3 Boilers at Iron and Steel Mills

Iron and steel mills utilize boilers on site to produce process steam and power for the mill. Fuels are typically COG, BFB and supplemented with natural gas. Some facilities may also utilize coal or oil. Information on how to control SO_2 from these boilers is contained in Section 2.1.

Table 16. SO$_2$ emissions from ferrous metals industry.

Industrial Processes - Ferrous Metals	Sum of emissions (tpy) 14,400	No. of sources 181
Iron Production /Cast House	2,983	19
Taconite Iron Ore Processing /Induration: Grate/Kiln, Coke & Coal-fired, Acid Pellets	2,879	2
Taconite Iron Ore Processing /Induration: Grate/Kiln, Coal-fired, Flux Pellets	1,573	7
Steel Manuf /Electric Arc Furnace: Carbon Steel (Stack)	1,137	14
Steel Manuf /Electric Arc Furnace: Alloy Steel (Stack)	874	4
Iron Production /Windbox	755	2
Taconite Iron Ore Processing /Induration: Grate/Kiln, Gas-fired, Flux Pellets	726	15
Ferroalloy, Open Furnace /Silicon Metal: Electric Smelting Furnace	590	1
Ferroalloy, Open Furnace /50% FeSi: Electric Smelting Furnace	554	1
Secondary Metals /Grey Iron Foundries /Cupola	546	15
Iron Production /Blast Furnace: Taphole and Trough	412	1
Taconite Iron Ore Processing /Induration: Straight Grate, Gas-fired, Acid Pellets	219	7
Steel Manuf /Other Not Classified	171	6
Secondary Metals /Steel Foundries /Heat Treating Furnace	160	4
Iron Production /Cooler	99	1
Secondary Metals /Steel Foundries /Electric Arc Furnace	76	12
Taconite Iron Ore Processing /Induration: Grate/Kiln, Gas-fired, Acid Pellets	74	4
Iron Production /Slag Crushing and Sizing	69	2
Steel Manuf /Basic Oxygen Furnace: Closed Hood-Stack	68	2
Steel Manuf /Q-BOP Melting and Refining	62	1
Taconite Iron Ore Processing /Induration: Straight Grate, Gas-fired, Flux Pellets	55	4
Secondary Metals /Grey Iron Foundries /Electric Arc Furnace	40	2
Steel Manuf /Tapping: Electric Arc Furnace	37	1
Steel Manuf /Hot Metal Desulfurization	31	6
Taconite Iron Ore Processing /Induration: Grate/Kiln, Gas & Oil-fired, Acid Pellets	29	2
Secondary Metals /Steel Foundries /Other Not Classified	25	2
Secondary Metals /Grey Iron Foundries /Pouring/Casting	20	7
Iron Production /Sinter Process (Combined Code includes 15,16,17,18)	15	9
Secondary Metals /Steel Foundries /Finishing	15	1
Steel Manuf /Continuous Casting	14	3
Steel Manuf /Charging: BOF	14	1
Steel Manuf /Tapping: BOF	13	1
Secondary Metals /Grey Iron Foundries /Core Making, Baking	10	1
Iron Production /Agglomerate Charging	8	2
Secondary Metals /Grey Iron Foundries /Castings Cooling	8	3

Industrial Processes - Ferrous Metals	Sum of emissions (tpy)	No. of sources
Secondary Metals /Grey Iron Foundries /Pouring, Cooling	7	2
Secondary Metals /Steel Foundries /Pouring/Casting	6	2
Secondary Metals /Steel Foundries /Sand Grinding/Handling	6	2
Steel Manuf /Basic Oxygen Furnace: Open Hood-Stack	4	1
Steel Manuf /Teeming (Unleaded Steel)	3	1
Secondary Metals /Grey Iron Foundries /Shell Core Machine	3	1
Ferroalloy, Open Furnace /80% Ferromanganese	2	1
Ferroalloy, Open Furnace /Silicomanaganese: Electric Smelting Furnace	2	1
Steel Manuf /Reheat Furnaces	2	1
Iron Production /Blast Heating Stoves	1	1
Secondary Metals /Grey Iron Foundries /Core Machines/Other	1	1
Steel Manuf /Pickling	1	1
Secondary Metals /Malleable Iron /Annealing	1	1

2.12. Petroleum Coke Calcining Kilns

2.12.1 Inventory and Control Measures

As Table 17 shows, two petroleum coke calciners are high emitters of SO_2. Each emits over 2,700 tpy or more of SO_2.

Table 17. Emissions from Petroleum Coke Calcination

	Sum of emissions (tpy)	No. of sources
Industrial Processes – Coke Calcining	**5,535.1**	**2**
Coke Calcining	5,535.1	2

Petroleum coke is calcined in order to drive off moisture and volatile organic compounds (VOCs) and refine the crystalline structure of the coke to produce a near pure carbon product with high electrical conductivity that can be used as anodes for aluminum smelting.

The "green" coke is fed to a rotary kiln, as shown in Figure 11. The VOCs driven off of the coke enter an afterburner where they are burned and the resulting heat used to generate steam in a heat recovery boiler. The afterburner, where the combustibles are oxidized, is often referred to as a Pyroscrubber, which is not a scrubber in the context of flue gas desulfurization but a device that removes organics through combustion.

There are limited process options for control of SO_2 from these units. To the extent that any sulfur-bearing fuel is used, that could be changed. The SO_2 emissions that result from volatiles that are driven off of the coke, however, can only be controlled with a downstream emissions control device. When there are downstream PM control devices, these might be used as part of an SO_2 capture system, and this is discussed in Chapter Three.

2.12.2 Regulations for Petroleum Coke Calcining Kilns

There is no LADCO White Paper for Petroleum Coke Calcining Kilns; however they are subject to NSPS; PSD/NSR and State Rules. Upcoming requirements that could have an impact on SO2 emissions include the regional haze rules and the SO_2 NAAQS.

Figure 11. Coke Calcination Process [24]
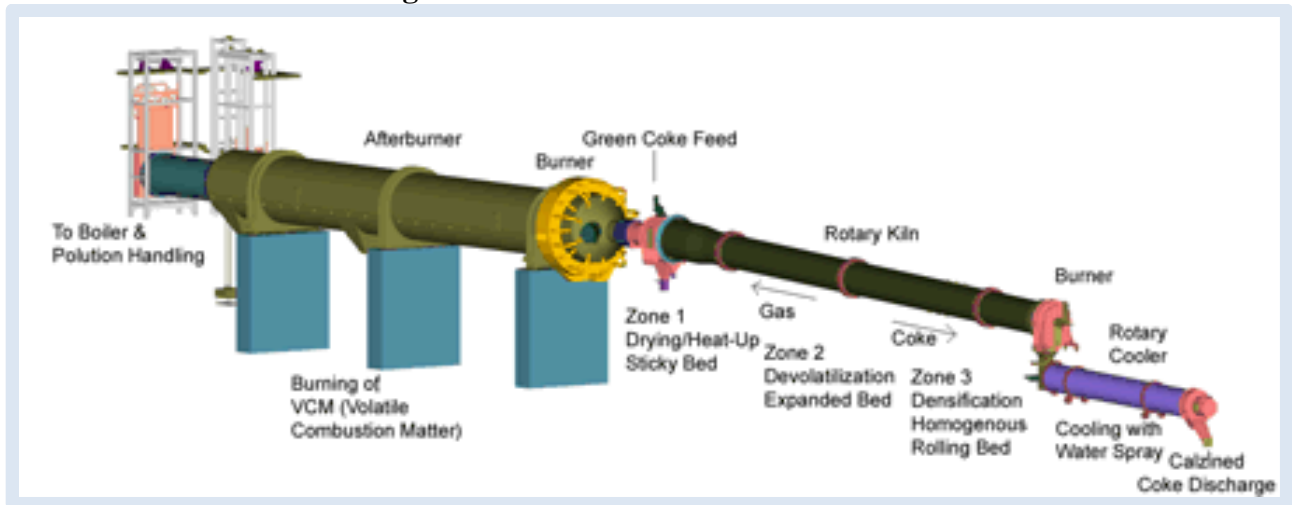
Chapter Three - Gas Treatment Technologies

As described in Chapter 2, many of the industrial sources can reduce the amount of SO2 created through changes in fuel, changes in raw materials, or changes to the process conditions; however, in many cases such changes may be uneconomical or impractical. For this reason, gas treatment methods that capture the SO_2 that is formed from these industrial sources may be the most effective form of controlling SO_2 emissions. Moreover, some of these industrial processes may already have gas treatment methods to capture PM or other emissions that can be complementary to the use of SO_2 capture methods. Examples of such gas treatment methods include wet PM scrubbers, fabric filters and electrostatic precipitators (ESPs). The types of flue gas SO_2 treatment methods are broadly

- Wet Flue Gas Desulfurization (FGD)
- Dry FGD
- Dry Sorbent Injection (DSI)

Sections 3.1 through 3.3 will provide technical descriptions of these processes and costs will be discussed in Section 3.4.

3.1 Wet FGD

In wet FGD systems water and a reagent are introduced to the treated gas together, typically as a solution or a slurry. The water cools the treated gas to below the saturation temperature, creating a "wet" gas. The reagent – typically an alkaline or alkali material (but sometimes another basic material) – reacts with the SO_2 and captures it into a solution, with the SO_2 typically forming a salt (calcium sulfite, sodium sulfite, etc.). The solution is recirculated and a portion of it the solution is bled off, which removes the sulfur-bearing salt. The amount of recirculation will depend upon the reagent being used and the amount of SO_2 being captured.

The reagent and the gas come in contact in an absorber, which is a reaction chamber that is sized to provide the reaction time for the absorption reaction and is configured to achieve good contact between the treated gas and the absorption liquid. Some scrubbers use trays, or packing or froth zones to improve reagent-gas contact. Figure 12 shows three types of absorbers – spray tower, tray, and packed bed. Figure 13 shows another configuration, a venturi scrubber, which provides PM control as well as SO2 control. Figure 14 shows a scrubber with a froth zone, and Figure 15 shows an EDV scrubber used in refinery applications for SO_2 capture. [25, 26] The

choice in scrubber will depend upon the solids loading of the dirty gas, the reagent being selected, whether particulate capture is desired and the degree of SO_2 capture needed. For example, spray towers are frequently used when particulate capture is not needed (there is an upstream PM control device) because they have the lowest pressure drop of any of the wet scrubber absorber types. They also permit multiple spray zones, which can promote high removal efficiency.

Modern wet FGD systems are capable of 90% to over 99% capture efficiencies, depending upon the design. State-of-the-art limestone wet FGD systems used in large power plants, achieve over 98% removal efficiency in retrofit systems (such as installed under the Clean Air Interstate Rule) and 99% removal efficiency in units subject to BACT. The higher removal efficiencies typically require more spray levels and residence time in the absorber, but single-stage limestone systems used in industrial settings typically achieve 90% or greater removal efficiencies. However, the infrastructure for a limestone forced oxidation system such as used in an electric utility plant is very costly and is rarely justified except on very large industrial facilities, such as very large industrial boilers and large cement plants. The advantages of such systems are higher removal efficiencies and the production of a high purity gypsum product. The ideal candidate for limestone wet FGD has: 1) large volume of gas to treat, 2) high SO_2 concentration in the gas, and 3) ability to address wet by product. Although limestone is widely used in utility wet FGD systems, there are other reagents. Wet FGD reagents might include:

- Limestone
- Lime
- Sodium carbonate (soda ash) or sodium hydroxide (caustic)
- Ammonia

Lime wet FGD will require a somewhat less capital intensive system than a limestone wet FGD system because lime is more reactive than limestone, but a lime wet FGD system is still relatively expensive since there still remains the need to recycle slurry. According to the US EPA's Title IV reporting, the industrial boiler in the United States with the lowest emission rate in 2010 was equipped with a wet lime FGD system, the 2866 MMBtu/hr Alcoa boiler in Indiana at 0.068 lb SO2/MMBtu.[c] However, lime is a more expensive reagent than limestone. As a

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[c] Determined by multiplying the reported total SO2 emissions in tons times 2000 to convert to pounds and dividing the product by the reported heat input in million Btu.

result, as limestone wet FGD systems have advanced in capability, lime wet FGD systems are not as frequently built for very large scrubbers. Today, lime is commonly used for dry FGD processes, which are discussed later in this report.

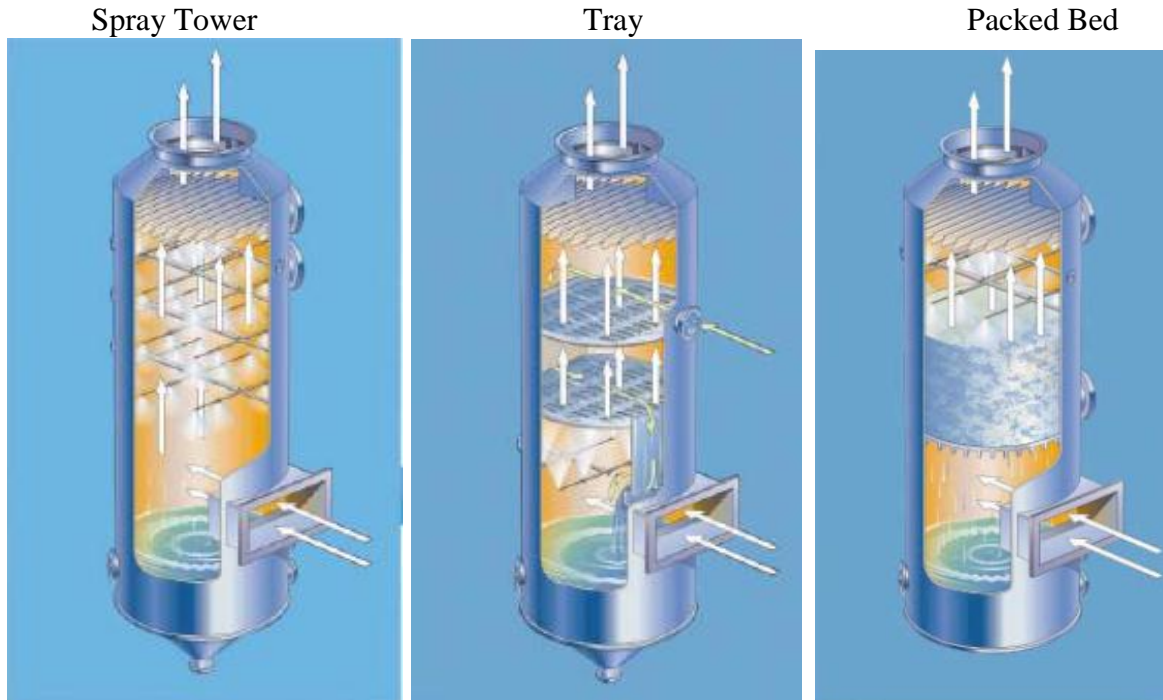**Figure 12.** Spray Tower, Tray and Packed Bed Scrubber Absorbers[27]

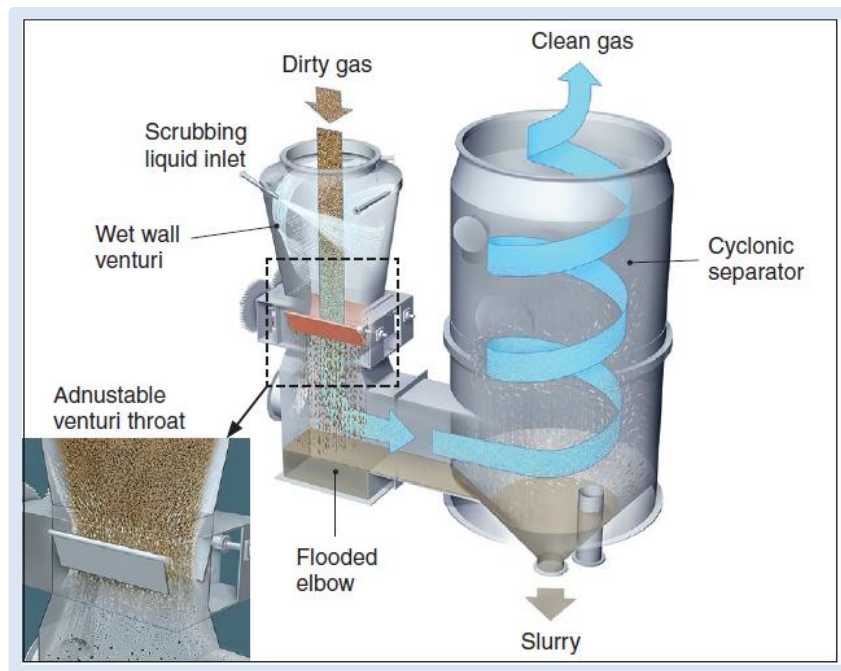| Spray Tower | Tray | Packed Bed |

Figure 13. Venturi Scrubber[28]
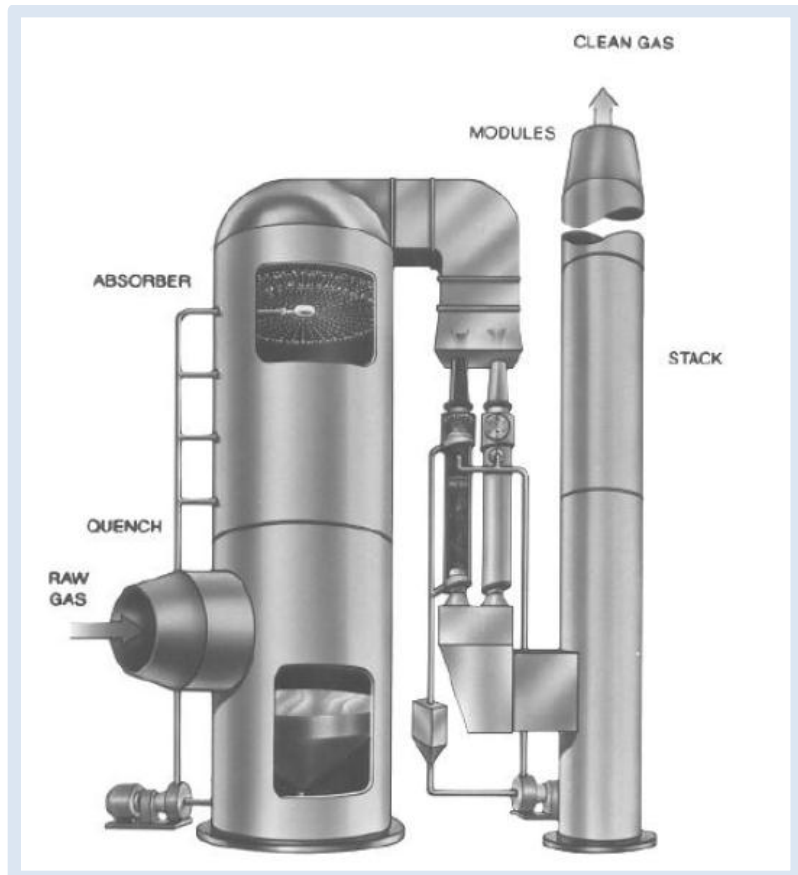
Figure 14. Dynawave Scrubber with Froth Zone [22]
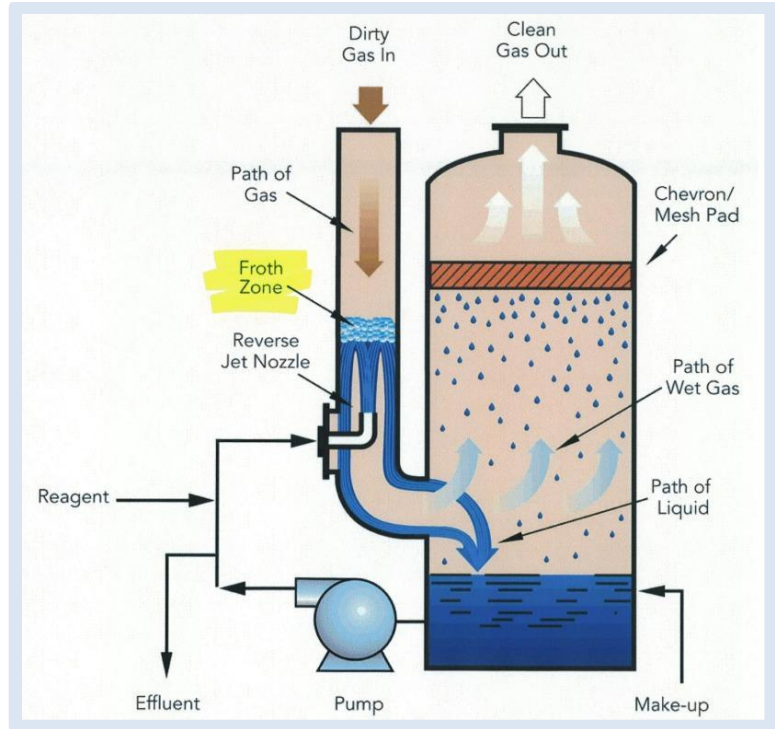
Figure 15 EDV scrubber typically used in refinery applications [23]

Wet FGD using water soluble reagents is more common at industrial facilities. These scrubbers use reagents such as caustic soda, soda ash, or other water soluble reagents that can utilize simpler pumping systems and much smaller absorber vessels since the reagents are much more reactive. Sodium-based reagents, such as soda ash and caustic soda are the most common reagents in use. The low liquid to gas ratios of sodium wet FGD enables the scrubber to be smaller and more responsive to changes in conditions.

US EPA's training materials[29] describe why sodium-based wet scrubbers are often selected for industrial applications:

- Sodium alkali is the most efficient of the commercial reagents in removing SO2, and the chemistry is relatively simple.
- They are soluble systems, as opposed to slurry systems, making for scale-free operation and fewer components.
- Such systems can handle the wider variations in flue-gas composition resulting from the burning of many different fuels by industry.
- The systems are often smaller, and operating costs are a small percentage of total plant costs.
- In some cases, these plants have a waste caustic stream or soda ash available for use as the absorbent

The simplicity of the water soluble reagent wet FGD systems also makes them very reliable in industrial settings, which is critical for facilities like refineries. In fact, Wet FGD has been deployed in several industries, especially refining (typically used on refinery FCCUs) and pulp and paper (fossil power boilers). Because of the use of wet PM scrubbers (venturi scrubbers) in many industrial applications, sodium wet FGD can often be readily incorporated into existing PM controls. Figure 16 shows data from EIA's Form 860 Reports. The data is the *reported* SO_2 removal efficiency of sodium scrubbers installed on industrial boilers plotted against the year in service. Most are venturi scrubbers, intended primarily for PM control. Typical removal efficiencies are on the order of 90%, but some scrubbers are reported to have in excess of 99% SO2 removal efficiency. The majority of these are venturi scrubbers, which remove both PM and SO_2. However, a US EPA study published in 1984 found that *measured SO_2 removal efficiency of 290 sodium scrubbers averaged over 93%*.[30] In case a facility already had an ESP for particle matter removal, a spray tower scrubber could likely be used. This would have the advantage of a lower cost and lower pressure drop than a venturi scrubber.

Use of wet FGD will likely require water treatment, or some other means of disposing of the liquid by-product. This is particularly true in the case of sodium scrubbers that have an aqueous stream with high total dissolved solids. Large industrial facilities, like paper mills, refineries, and steel mills, often have water treatment facilities on site and can therefore accept the waste water generated from a wet FGD system, and this is why sodium scrubbers are used in these applications. Some industrial facilities, such as pulp mills, utilize caustic and sodium sulfide on site and may be able to reutilize by-product from the wet scrubber.

Figure 16. SO_2 Removal Efficiency of Sodium Wet Scrubbers by Year in Service[31]

Source: EIA Form 860
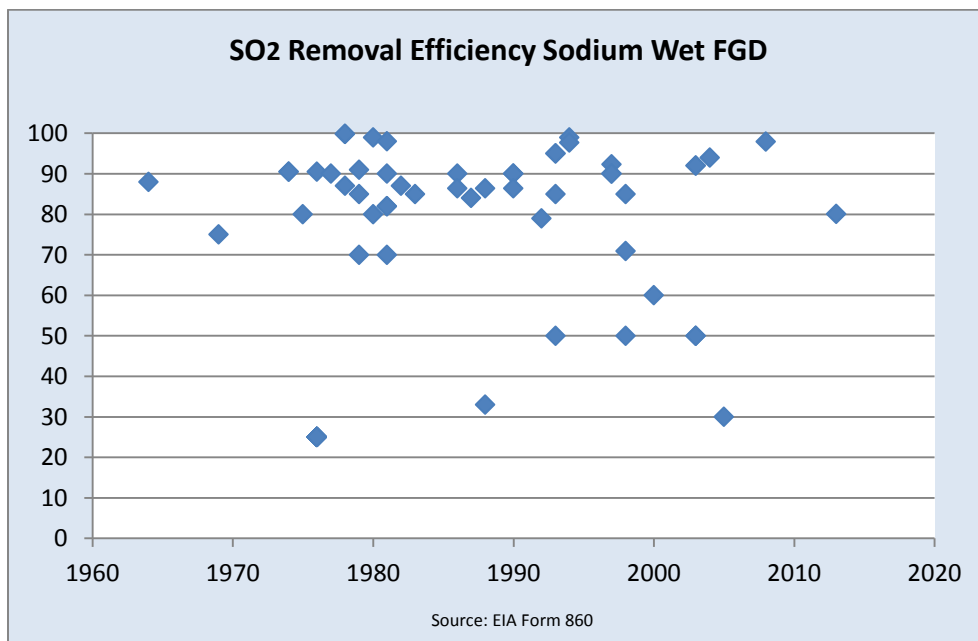
Cobenefits of wet FGD

Wet FGD has been shown to have some cobenefits in terms of removal of other pollutants besides SO_2. Most of the data available has been developed from electric utility testing of limestone forced oxidation wet FGD systems. So, some of the cobenefit effects might differ somewhat for other wet FGD systems.

- *HCl and HF* – High removal of HCl and HF are expected with a wet FGD system due to the high reactivity of these acid gases. They types of coals burned in the LADCO region (Northern Appalachian and Illinois Basin) tend to have significant concentration of chlorides, which contribute to HCl emissions.

- *Hg* – Oxidized mercury tends to be efficiently captured in wet FGD systems while elemental mercury is not captured. In some cases some oxidized mercury that has been captured has been reemitted as elemental mercury, which will reduce the net capture efficiency of the oxidized mercury. Northern Appalachian and Illinois Basin coals tend to produce mostly oxidized mercury due to the chlorine in the coal. Elemental mercury can be converted to oxidized mercury through bromide addition to the fuel or with an SCR NOx control system.

- *Filterable PM* – Filterable PM capture can be high in venturi wet scrubbers that are designed for high PM capture. Spray towers will have low filterable PM capture.

- *Condensable PM* – Although most sulfur forms SO_2, some of the sulfur in the fuel will oxidize to form SO_3, which later forms H_2SO_4, a main component of condensable PM. SO_3 will be captured to some degree by a wet scrubber (typically in the range of about 50%), which reduces condensable PM emissions; however, the moist gas from a wet scrubber can cause some sulfuric acid fume to form from the remaining SO_3.

Considerations for wet FGD

Wet FGD will require make up water and will produce a wet product, which will make water treatment or ponding likely. The gypsum product from high efficiency limestone wet FGD that is similar to what is used in large electric utility plants (also sometimes called "Advanced FGD" in some of the reports by MACTEC for LADCO) can be sold as wallboard-quality gypsum. The energy demand from wet FGD can be significant, especially for limestone wet FGD (high pumping costs and pressure drop) or for venturi wet scrubbers (due to the high pressure drop).

3.2 Dry FGD

Dry FGD systems have the advantage of producing a dry, solid by-product. The by-product is normally capable of being landfilled and therefore avoids the need for water treatment. Although other reagents (such as sodium-based reagents) have been used, by far the most common reagent for dry FGD systems is lime, which results in a dry product that is not water soluble, and therefore is easily landfilled. In dry FGD systems, water and lime are injected. The water cools the gas, but does not cool it to the point of saturation, so that no droplets form. The lime reacts with the SO_2 to form a dry product. Dry FGD systems are capable of greater than 90% SO_2 removal. Examples of these are Spray Dryer Absorbers (SDA), as depicted in Figure 17, or Circulating Dry Scrubbers (CDS), as depicted in Figure 18. In both cases downstream PM removal devices are necessary, and baghouses are most commonly used although a small number of facilities have used downstream ESPs. CDS systems can achieve higher removal rates than SDA systems, especially in high SO_2 environments. This is because the water and lime are introduced separately, rather than together in a slurry.

According to US EPA's 2010 Annual Title IV reporting data, several industrial boilers and small power boilers use dry lime FGD with a baghouse for SO_2 control. In fact, among the twenty Title IV-affected industrial boilers, cogeneration boilers, or small power boilers with the lowest emission rates in 2010, thirteen of them have dry lime scrubbers with baghouses as the sole method of control (ie., circulating fluid bed boilers with downstream scrubbers are not included among the thirteen).[c] The median size of these boilers is 525 MMBtu/hr (average size is 712 MMBtu/hr) and the average and median SO_2 emission rates are 0.095 lb/MMBtu. Therefore, emissions rates below 0.10 lb SO_2/MMBtu are achievable with dry FGD systems depending upon the coal sulfur content. CDS technology (Babcock Power Turbosorp) has demonstrated that it can provide 96% removal and 0.15 lb SO_2/MMBtu emissions with coal that would produce 3.6 lb SO_2/MMBtu uncontrolled at the AES Greenidge plant, which is a small utility boiler of roughly 100 MW capacity.[32]
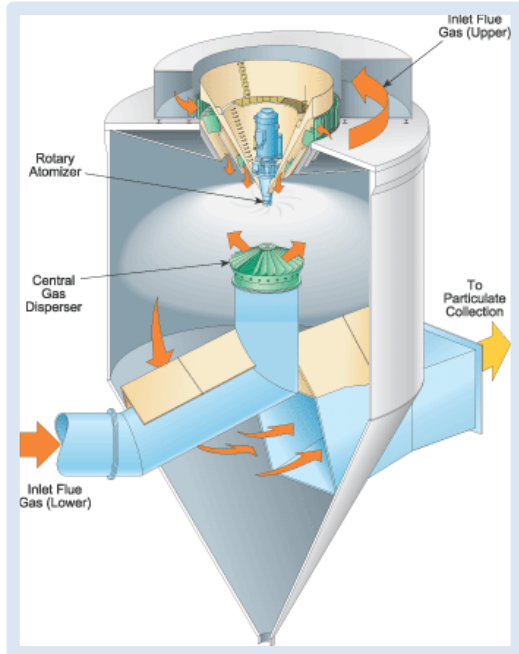
Figure 17. A Spray Dryer Absorber
Lime reagent and water mixture are atomized and coinjected into a reaction vessel with flue gas. As the injected droplets dry, they react with SO_2 in the gas and the dry product is sent to a fabric filter for capture.
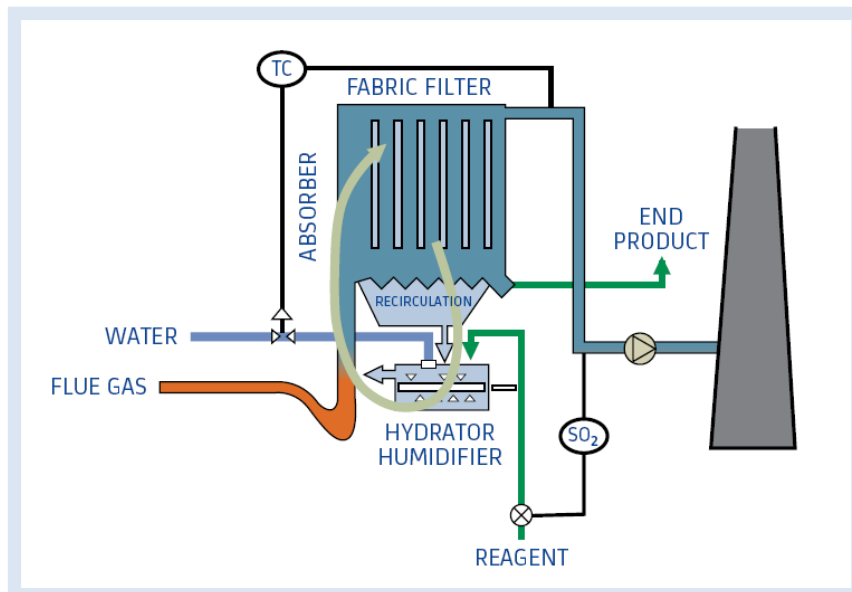
Figure from Babcock & Wilcox Company

Figure 18. A Circulating Dry Scrubber –
Lime reagent and water are introduced separately to cool gas and make a humidified reagent. The lime reacts with SO_2 in the cooled gas, The dry product is captured in a fabric filter and recirculated to increase reagent utilization.

Figure from Alstom Environmental Control Systems

Dry FGD systems are often added to circulating fluid bed (CFB) boilers to provide additional SO_2 reduction beyond the roughly 90% SO_2 capture that can occur in the furnace through limestone injection. In combination, limestone injection on a CFB and dry FGD can provide 99% SO_2 capture by capturing 90% in the bed and capturing 90% of the remaining SO_2 in the dry FGD system.

Because of the generally high SO_2 content of local coal used in the LADCO region, a CDS scrubber may be preferred for most non-CFB boilers in the LADCO region that burn coal. CDS scrubbers tend to be slightly more expensive with regard to capital cost than SDA's. This is in part because the fabric filter must be elevated to a higher level than would be the case for an SDA in order to accommodate the recirculation of reagent/product. For other industrial gas applications, the selection of SDA or CDS will be determined by the sulfur content in the gas and the degree of removal needed.

Cobenefits of dry FGD

Dry FGD has been shown to have substantial cobenefits in terms of removal of other pollutants besides SO_2. Most of the data available has been developed from electric utility testing dry FGD systems.

- *HCl and HF* – High removal of HCl and HF are expected with a dy FGD system due to the high reactivity of these acid gases. They types of coals burned in the LADCO region (Northern Appalachian and Illinois Basin) tend to have significant concentration of chlorides, which contribute to HCl emissions.
- *Hg* – Dry FGD systems tend to have very high capture efficiencies for both forms of mercury, especially when there is significant halogen (chlorine/fluorine) present, such as in the coals burned in the LADCO region.
- *Filterable PM* – Because a dry FGD system normally has a baghouse, high filterable PM removal normally results.
- *Condensable PM* – Although most sulfur forms SO_2, some of the sulfur in the fuel will oxidize to form SO_3, which later forms H_2SO_4, a main component of condensable PM. SO_3 will be captured very effectively in dry FGD systems.

Considerations for Dry FGD

Dry FGD using lime produces a dry, stable product that is not water soluble and can be reutilized or landfilled without difficulty. Pressure drop is significant, especially because of the baghouse. Dry FGD will require water, but less water than a wet FGD system.

3.3 Dry Sorbent Injection (DSI)

DSI is performed by injecting a dry reagent into the gas stream that reacts with and captures SO_2.   Figure 19 shows an example of a DSI system. After the sorbent reacts with the SO_2, a downstream PM control device, such as ESP or baghouse, captures the dry product.   DSI is capable of high capture rates (over 80%) for SO2 when used in combination with a fabric filter and moderate removal rates (over 50%) when used upstream of an ESP. Compared to wet or dry FGD, DSI has the advantage of being relatively low in capital cost, requires very limited space, and therefore can be very easily retrofit; however, DSI requires more expensive reagent (typically Trona, sodium bicarbonate, or a highly activated lime hydrate). Trona and sodium bicarbonate (SBC) are both sodium-based reagents. Trona is a naturally-occurring mineral that is mined in Wyoming. SBC can be produced from trona or is mined as naturally-occurring nahcolite. Trona is mined primarily to produce soda ash (sodium carbonate) which is used in a variety of applications. Activated lime hydrate is another possible reagent for DSI. There is less experience with it; however, it offers the advantage of producing a stable by-product that is not water soluble and therefore poses no difficulties with regard to disposal.

Figure 19. A DSI System[33]
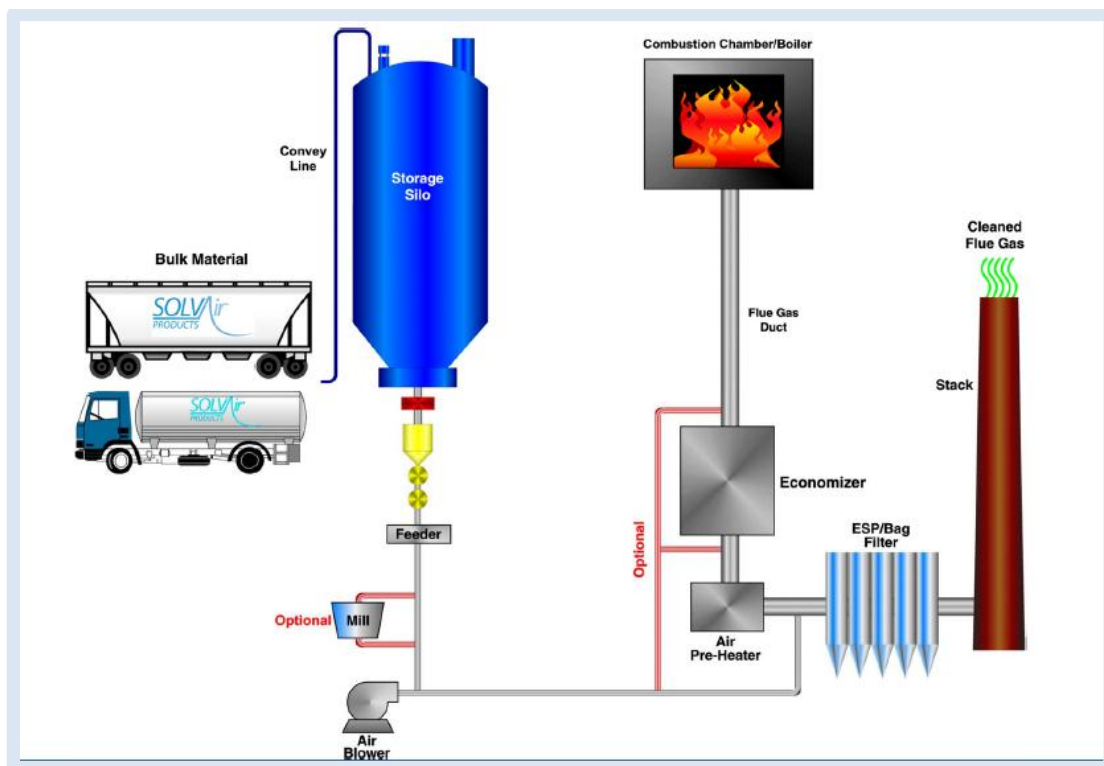
DSI has been used in a number of applications, including electric utility, municipal waste, and others for control of SO_2, SO_3 or other acid gases. The equipment used in a DSI is relatively straightforward equipment – silo for storage, solids metering, blowers and piping for pneumatic conveying, and lances for blowing and distributing the sorbent in the ductwork.

DSI is especially well suited for facilities with existing PM control devices, that have moderate SO_2 levels and require moderate levels of control. Because the reagent for DSI is more expensive and is less efficiently utilized than the reagent for dry or wet FGD, it will generally be unattractive compared to dry FGD or to wet FGD in situations with high SO_2 concentrations.

The selection of reagent will depend upon a number of factors. Figures 19 a through d compare the SO_2 removal capability of trona to that of SBC under varying reagent treatment rates in situations with an ESP or with a baghouse. NSR stands for normalized stoichiometric ratio, and is equal to the ratio of the treatment rate to that of the SO_2 being treated. The chemical reactions are as follows:[33]

- Trona decomposition to sodium carbonate
  $2(Na_2CO_3•NaHCO_3• 2H_2O)(s) + heat \rightarrow 3Na_2CO_3(s) + 5H_2O(g) + CO_2(g)$
- Sodium Bicarbonate decomposition to sodium carbonate
  $2NaHCO_3(s) + heat \rightarrow Na_2CO_3(s) + H_2O(g) + CO_2(g)$
- Reduction of SO2 is by the reaction,
  $Na_2CO_3(s) + SO_2 + \frac{1}{2}O_2 \rightarrow Na_2SO_4(s) + CO_2(g)$

So, an NSR of 1.0 results in 2 moles of trona to 3 moles of SO_2 in the gas, or 2.35 lbs of trona to each lb of SO_2 in the gas. For SBC an NSR of 1.0 results in 2 moles of SBC per mole of SO_2 being treated or 2.63 lbs of SBC per lb of SO_2 being treated. As shown in Figures 20 a through d, SBC will result in higher SO_2 capture at any given NSR than trona, and DSI with a downstream fabric filter will always result in higher capture rates for a given reagent treatment rate than DSI with a downstream ESP. SBC is somewhat more expensive per pound than trona, however, since a large portion of the delivered cost is freight, the difference in cost can be overcome by the lower treatment rate of the SBC. This is particularly true with regard to DSI upstream of an ESP.

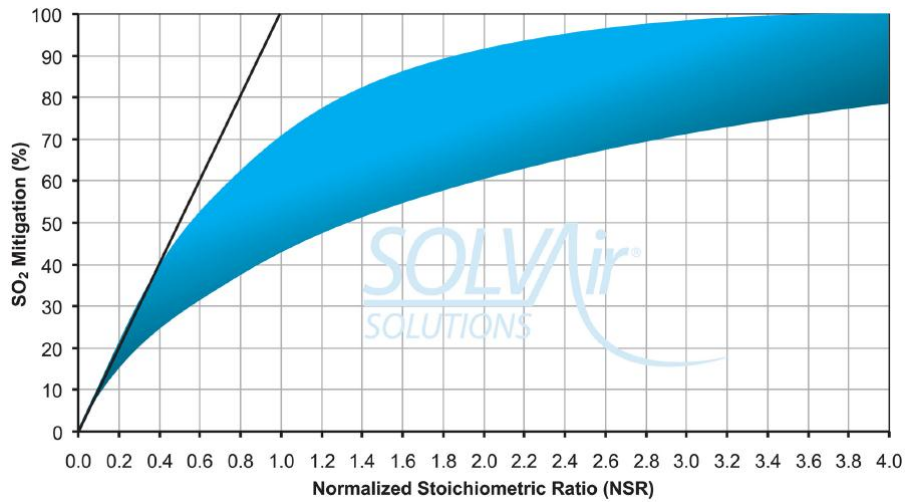**Figure 20a.** DSI with Trona upstream of an ESP [30]
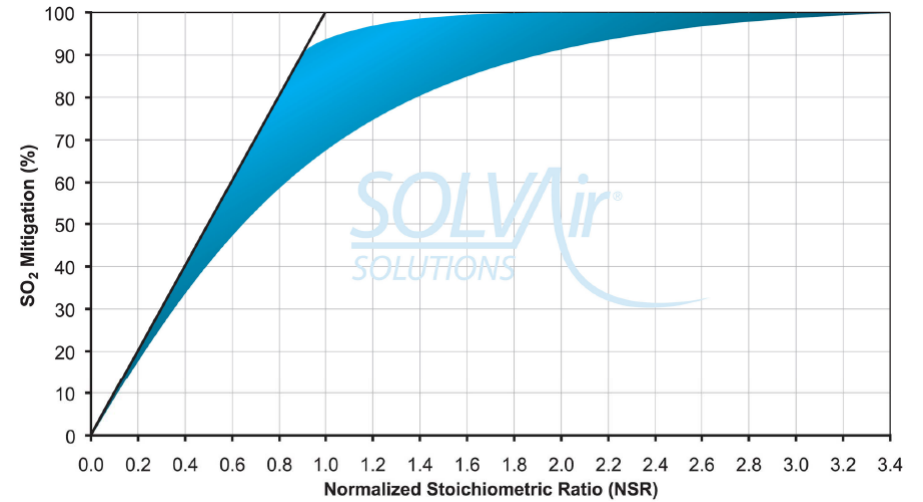

Figure 20b. DSI with SBC upstream of an ESP [30]
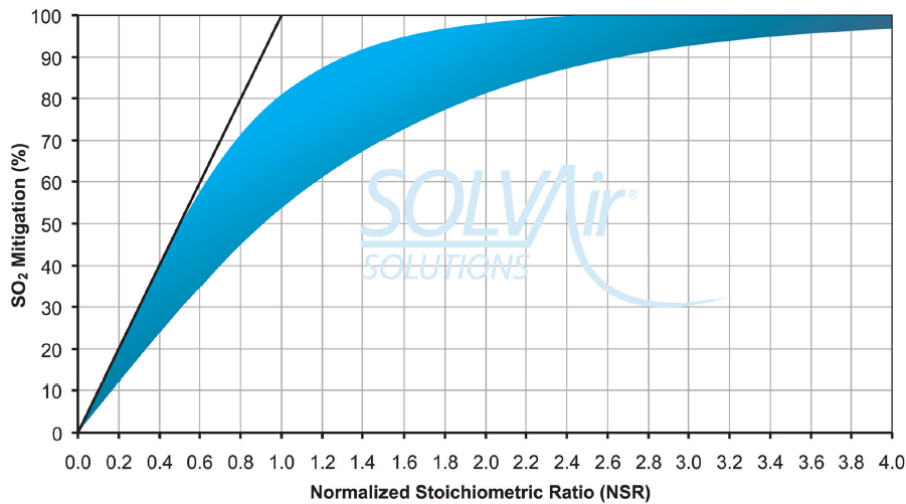

Figure 20c. DSI with Trona upstream of a baghouse [30]

Figure 20d. DSI with SBC upstream of a baghouse[30]

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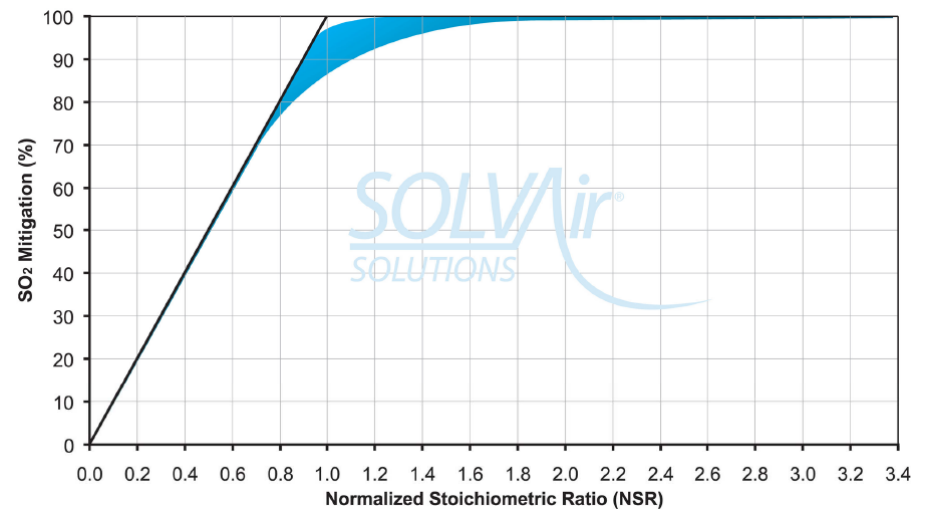
Lime hydrate is also used for DSI; however, for DSI it is ideally in a more activated form than is typical for lime used for other applications, such as dry FGD. Lime DSI has the advantage of producing a dry product that is not water soluble and can readily be landfilled or reutilized for other purposes (ie., soil stabilization, etc.). Pilot testing at Southern Research Institute showed over 60% "in flight" SO_2 capture with activated lime hydrate. With a fabric filter SO_2 capture would have been higher. [34]

Cobenefits of DSI

DSI has been shown to have cobenefits in terms of removal of other pollutants besides SO_2. Most of the data available has been developed from electric utility testing DSI systems.

- *HCl and HF* – HCl and HF are removed as well with DSI. High capture efficiencies are possible, and capture efficiency of HCl is generally higher than that for SO_2.
- *Hg* – For bituminous coals DSI will generally improve mercury capture in the PM control device, especially if activated carbon is used because DSI will remove SO3 that competes with mercury for adsorption onto fly ash or activated carbon. When using Powder River Basin (PRB) coals in a boiler, DSI using trona or SBC can actually inhibit mercury capture somewhat because trona can contribute NO_2 formation from NO, and the NO_2 interferes with the capture by activated carbon. This phenomenon with NO conversion, however, is not expected to occur with lime hydrate.
- *Filterable PM* – Trona or SBC injected upstream of an ESP will actually improve ESP performance because of the beneficial effect that the sodium has on fly ash resistivity. Lime hydrate will not have the same beneficial effect and will increase PM emissions somewhat.
- *Condensable PM* – Although most sulfur forms SO_2, some of the sulfur in the fuel will oxidize to form SO3, which later forms H_2SO_4, a main component of condensable PM. SO_3 concentration will be reduced by a DSI system.
- *NOx* – DSI using trona or sodium bicarbonate can provide some NOx reduction benefit.

Considerations for DSI

DSI using lime produces a dry, stable product that is not water soluble and can be beneficially reutilized or landfilled easily. DSI with Trona or SBC, on the other hand, results in

a dry, but water soluble, product. Depending upon the other constituents in the fly ash that are captured in the PM control device, additional stabilization may be necessary prior to disposal.

At high injection rates on units without NOx controls, DSI may convert some NO to NO_2, which under some conditions can result in a brown plume. This is addressed by reducing injection rates.

3.4 Costs of Controlling SO_2

This section will examine the costs of controlling SO_2 in the following situations:

- First, the costs of FGD treatment systems, particularly for industrial boiler, but also for most other sources are examined in generic terms– limestone wet FGD, sodium wet FGD, and lime dry FGD.
- Second, the cost of wet FGD on cement kilns and SO_2 reduction on refinery applications is examined.
- Third, the cost of DSI systems are examined
- Finally, the estimated cost for situations where existing PM controls may permit low cost SO_2 reductions on industrial sources will be examined.

3.4.1 Cost of Dry and Wet FGD on Industrial Boilers

Table 18 shows the costs for control of wet and dry FGD in terms of $/ton of SO_2 reduced for various control methods and boiler types. The costs were developed by several sources and therefore cover a wide range of situations and time periods.   Factors that impact cost are:

- Technology selection – Some technologies have higher capital cost, but may also have additional control benefits.   Limestone Wet FGD can result in a marketable by product. Dry FGD offers high PM capture and a dry product. Sodium wet scrubbing, on the other hand, is a low cost approach for many industrial boilers because of its low capital cost, providing that water treatment is available on site and providing that the sodium reagent remains reasonable in price.
- Uncontrolled SO_2 level – lower initial SO_2 levels will result in higher costs represented in $/ton of SO_2 removed.
- Facility Size – Larger boilers tend to benefit from economies of scale in terms of capital cost.

Table 18 . Costs of SO$_2$ Control for Wet and Dry FGD on ICI Boilers

Emission Source	Technology	Percent Reduction	$/ton SO$_2$ Removed	year $	source
ICI Boilers - Coal– 100 MMBtu/hr	Lime dry FGD	85%	$1590-$7690	2008	1
ICI Boilers – Coal – 250 MMBtu/hr	Lime dry FGD	85%	$1480-$4010	2008	1
ICI Boilers – Coal – 750 MMBtu/hr	Lime dry FGD	85%	$1420-$2380	2008	1
ICI Boilers - Coal– 100 MMBtu/hr	Lime wet FGD	85%	$1650-$7510	2008	1
ICI Boilers - Coal– 250 MMBtu/hr	Lime wet FGD	85%	$1400-$3830	2008	1
ICI Boilers - Coal– 750 MMBtu/hr	Lime wet FGD	85%	$1290-$2220	2008	1
ICI Boiler – Coal	Spray Dryer	90%	$1,712-3,578	2005	2
ICI Boiler – Coal	Spray Dryer	95%	$1,622-3,390	2005	2
ICI Boiler – Oil	Spray Dryer	90%	$1,944-5,219	2005	2
ICI Boiler – Oil	Spray Dryer	95%	$1,841-4,945	2005	2
ICI Boiler – Coal	Limestone wFGD	90%	$2,089-3,822	2005	2
ICI Boiler – Coal	Limestone wFGD	99%	$1,881-3,440	2005	2
ICI Boiler – Oil	Limestone wFGD	90%	$2,173-5,215	2005	2
ICI Boiler – Oil	Limestone wFGD	99%	$1,956-4,694	2005	2
ICI Boiler Coal 250 MMBtu/hr	Limestone wFGD	95%	$4,427	2006	3
ICI Boiler Coal 100 MMBtu/hr	Limestone wFGD	95%	$9,547	2006	3
ICI Boiler No.6 Oil 250 MMBtu/hr	Limestone wFGD	95%	$5,713	2006	3
ICI Boiler No.6 Oil 100 MMBtu/hr	Limestone wFGD	95%	$12,510	2006	3
ICI Boiler Coal 250 MMBtu/hr	Lime Dry FGD	90%	$3,694	2006	3
ICI Boiler Coal 100 MMBtu/hr	Lime Dry FGD	90%	$7,909	2006	3
ICI Boiler No.6 Oil 250 MMBtu/hr	Lime Dry FGD	90%	$4,704	2006	3
ICI Boiler No.6 Oil 100 MMBtu/hr	Lime Dry FGD	90%	$10,352	2006	3
ICI Boiler, 210 MMBtu/hr, 5.75 lbSO2/MMBtu	Lime Dry FGD	90%	$1,000	2009	4
ICI Boiler, 210 MMBtu/hr, 2.59 lbSO2/MMBtu	Lime Dry FGD	90%	$2,000	2009	4
ICI Boiler, 210 MMBtu/hr, 1.15 lbSO2/MMBtu	Lime Dry FGD	90%	$4,200	2009	4
ICI Boiler, 210 MMBtu/hr, 0.5 lbSO2/MMBtu	Lime Dry FGD	90%	$9,500	2009	4
ICI Boiler, 420 MMBtu/hr, 5.75 lbSO2/MMBtu	Lime Dry FGD	90%	$700	2009	4
ICI Boiler, 420 MMBtu/hr, 2.59 lbSO2/MMBtu	Lime Dry FGD	90%	$1,400	2009	4
ICI Boiler, 420 MMBtu/hr, 1.15 lbSO2/MMBtu	Lime Dry FGD	90%	$2,900	2009	4
ICI Boiler, 420 MMBtu/hr, 0.5 lbSO2/MMBtu	Lime Dry FGD	90%	$6,600	2009	4
ICI Boiler, 630 MMBtu/hr, 5.75 lbSO2/MMBtu	Lime Dry FGD	90%	$600	2009	4
ICI Boiler, 630 MMBtu/hr, 2.59 lbSO2/MMBtu	Lime Dry FGD	90%	$1,200	2009	4

Emission Source	Technology	Percent Reduction	$/ton SO₂ Removed	year $	source
ICI Boiler, 630 MMBtu/hr, 1.15 lbSO2/MMBtu	Lime Dry FGD	90%	$2,400	2009	4
ICI Boiler, 630 MMBtu/hr, 0.5 lbSO2/MMBtu	Lime Dry FGD	90%	$5,400	2009	4
ICI Boiler, 210 MMBtu/hr, 5.75 lbSO2/MMBtu	Sodium wet FGD*	90%	$800	2009	4
ICI Boiler, 210 MMBtu/hr, 2.59 lbSO2/MMBtu	Sodium wet FGD*	90%	$1,130	2009	4
ICI Boiler, 210 MMBtu/hr, 1.15 lbSO2/MMBtu	Sodium wet FGD*	90%	$1,790	2009	4
ICI Boiler, 210 MMBtu/hr, 0.5 lbSO2/MMBtu	Sodium wet FGD*	90%	$3,770	2009	4
ICI Boiler, 420 MMBtu/hr, 5.75 lbSO2/MMBtu	Sodium wet FGD*	90%	$630	2009	4
ICI Boiler, 420 MMBtu/hr, 2.59 lbSO2/MMBtu	Sodium wet FGD*	90%	$890	2009	4
ICI Boiler, 420 MMBtu/hr, 1.15 lbSO2/MMBtu	Sodium wet FGD*	90%	$1,400	2009	4
ICI Boiler, 420 MMBtu/hr, 0.5 lbSO2/MMBtu	Sodium wet FGD*	90%	$2,940	2009	4
ICI Boiler, 630 MMBtu/hr, 5.75 lbSO2/MMBtu	Sodium wet FGD*	90%	$600	2009	4
ICI Boiler, 630 MMBtu/hr, 2.59 lbSO2/MMBtu	Sodium wet FGD*	90%	$830	2009	4
ICI Boiler, 630 MMBtu/hr, 1.15 lbSO2/MMBtu	Sodium wet FGD*	90%	$1,270	2009	4
ICI Boiler, 630 MMBtu/hr, 0.5 lbSO2/MMBtu	Sodium wet FGD*	90%	$2,600	2009	4

Notes:
* Sodium FGD cost does not include cost of water treatment. Cost of caustic soda is assumed to be $400/ton

Sources:

1. Ozone Transport Commission (OTC) / Lake Michigan Air Directors Consortium (LADCO), "Evaluation of Control Options for Industrial, Commercial and Institutional (ICI) Boilers - Technical Support Document (TSD) – Draft", 5/25/10
2. MACTEC, Boiler Best Available Retrofit Technology (BART) Engineering Analysis; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.
3. NESCAUM, Applicability and Feasibility of NOx, SO₂, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers", November 2008
4. Staudt, J., "Costs of Emission Control Technologies", presentation to Lake Michigan Air Directors Consortium (LADCO), ICAC-LADCO Meeting

3.4.2 The Costs of Control with DSI Systems

Although DSI systems have been examined for decades, they have not been seriously considered for SO_2 control because changing fuels and scrubbing have generally been more economical and therefore more widely used under the emissions trading rules such as Title IV and the Clean Air Interstate Rule. As regulations have required further reductions, companies are examining DSI for facilities where the capital expenditure of a scrubber is less justified. Using the information in Section 3.3 on DSI and the following cost and performance assumptions,

Capital Cost:
- $9,700/MMBtu/hr to $14,000/MMBtu/hr, depending upon size of unit if an additional fabric filter will not be required.
- $35,000/MMBtu/hr to $80,000/MMBtu/hr depending upon size of unit if an additional fabric filter is installed.

Trona Cost: $150/ton delivered
SBC cost: $200/ton delivered
Waste disposal, $30/ton
Fabric filter operating cost, depending upon size, from $350,000/yr to $530,000/yr

Treatment rates

- Trona with ESP: NSR=1.50, 65% reduction
- Trona with FF: NSR=1.50; 80% reduction
- SBC with ESP NSR=1.5; 90% reduction
- SBC with FF: NSR = 1.0; 90% reduction

Different coals were selected to achieve different SO_2 emission rates, with calculations performed using US EPA's CUECost model.

Figures 21a, 21b and 21c, SO_2 demonstrate reductions are in the range of $2000/ton when the uncontrolled emission rate is only 0.50 lb/MMBtu and a new FF is not needed, but this corresponds with one of the lower sulfur content PRB coals, which, while common for utility boilers, would be unusual for an industrial boiler in the LADCO region. Depending upon the choice of SBC or trona, SO_2 capture can be achieved for near $1000/ton, or even less if the boiler already has a fabric filter. Figure 21c demonstrates that costs are higher when the cost of a new fabric filter is included.   For the conditions shown, SBC is generally somewhat more cost effective in SO_2 capture, and this is because the higher reactivity of the SBC more than compensates for the higher reagent cost under the circumstances shown here. Of course, as

Figures 20 a through d show, there is some variability to the performance based upon the particulars of the facility, so this should be examined with regard to the particular application.

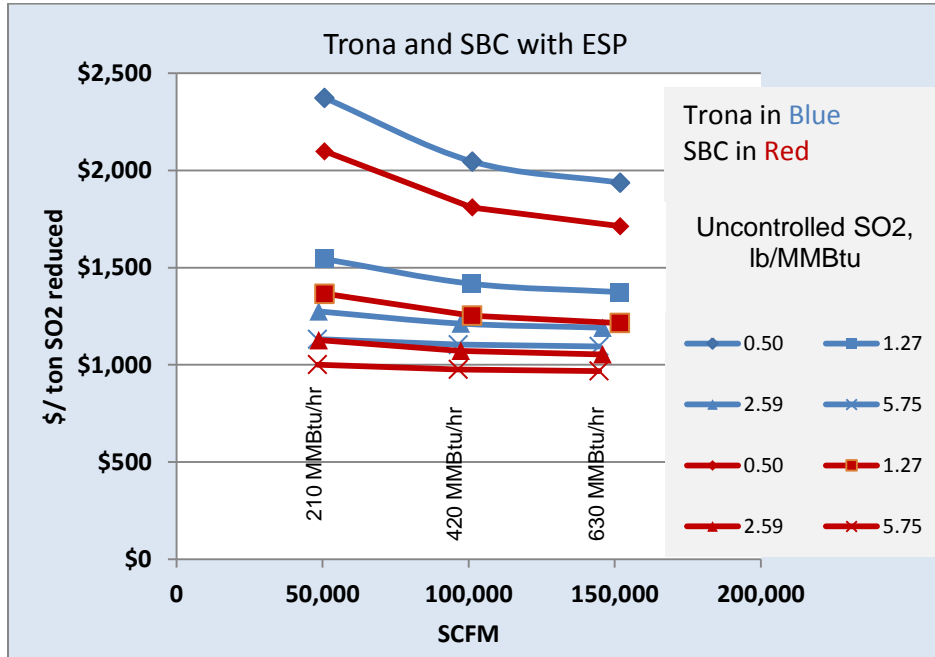**Figure 21a.** Cost of SO_2 reduction by DSI with Existing ESP

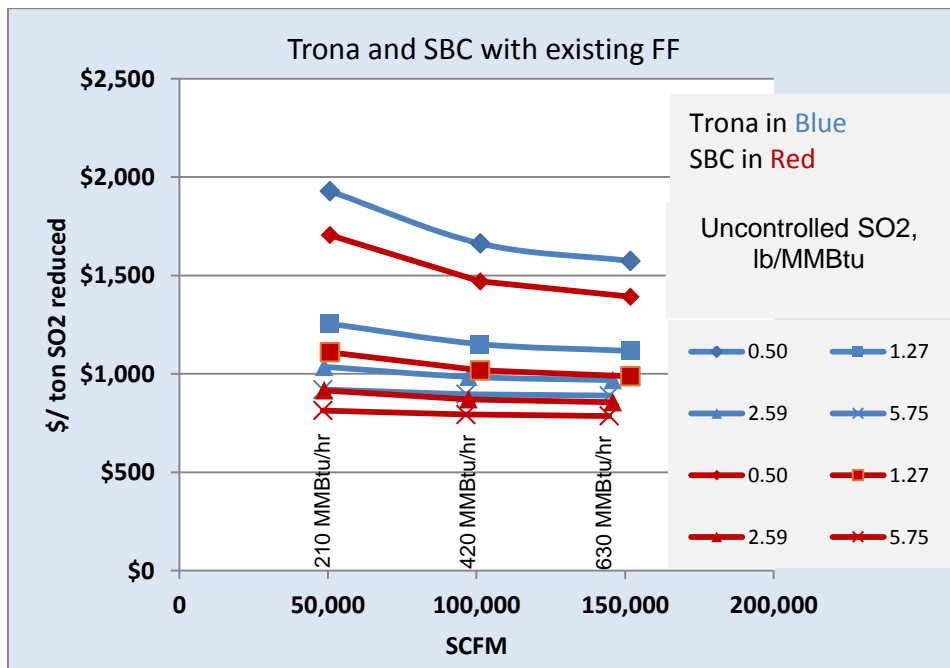**Figure. 21b.** Cost of SO_2 reduction by DSI with Existing FF
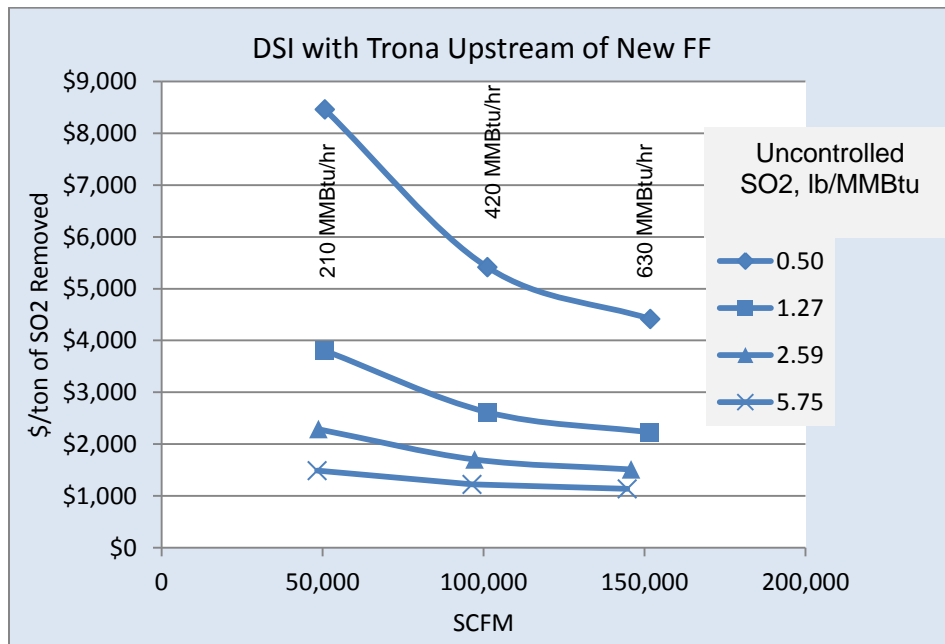
Figure 21c. Cost of SO$_2$ reduction by DSI with New downstream FF

3.4.3 Cost of Controls on Cement Kilns and Refinery Applications

Table 19 lists data on the cost of reducing SO_2 emissions from Portland Cement kilns, Refinery FCCU's and Refinery Process heaters. As shown the costs for cement kiln scrubbers cover a wide range. This is in part due to the limited experience with wet FGD on cement kilns that had created uncertainty about cost. The information by Staudt was developed based upon capital and operating cost estimates developed for US EPA's Industrial Sector Integrated Solutions (ISIS) model that relied on input from the Portland Cement Association and measured kiln conditions.[35] The estimates developed by MACTEC covered a wide range, mainly because of a very wide uncertainty range for capital cost (well over a factor of 10 in several cases). Based upon the information by Staudt, it appears that the lower range of costs from the MACTEC estimates should be used.

The costs of refinery SO_2 reduction methods are also shown. The cost of the scrubber for an FCCU is relatively low, and this is because this is a sodium scrubber. The cost of capturing SO_2 from process heater is estimated to be much higher. This is partly because the assumption was a calcium-based sorbent, which results in a higher capital cost than a sodium scrubber. In practice, refinery process heaters generally use sodium wet scrubbers because of the high reliability and simplicity of these scrubbers, and low capital cost. Refineries generally have water treatment plants.

Table 19. SO$_2$ Control Costs for Cement Kilns and Refinery Units

Facility Type	Technology	% Reduction	$/ton removed	Year	Source
All Kilns	Lime Absorbent addition	60%-80%	2031-7379	2005	1
300000 TPY Long Dry Cement Kiln	AFGD	95	2187-4218	2005	1
600000 TPY Long Dry Cement Kiln	AFGD	95	2152-4183	2005	1
1200000 TPY Long Dry Cement Kiln	AFGD	95	2134-4165	2005	1
300000 TPY Long Dry Cement Kiln	Wet FGD	90	2256-6861	2005	1
600000 TPY Long Dry Cement Kiln	Wet FGD	90	2226-6831	2005	1
1200000 TPY Long Dry Cement Kiln	Wet FGD	90	2211-6816	2005	1
300000 TPY Long Dry Cement Kiln	Dry FGD	90	2111-6917	2005	1
600000 TPY Long Dry Cement Kiln	Dry FGD	90	2031-7379	2005	1
1200000 TPY Long Dry Cement Kiln	Dry FGD	90	1986-7201	2005	1
300000 TPY Preheater Cement Kiln	AFGD	95	15177-38568	2005	1
600000 TPY Preheater Cement Kiln	AFGD	95	14536-37927	2005	1
1200000 TPY Preheater Cement Kiln	AFGD	95	14215-37607	2005	1
300000 TPY Preheater Cement Kiln	Wet FGD	90	11547-64573	2005	1
600000 TPY Preheater Cement Kiln	Wet FGD	90	11006-64032	2005	1
1200000 TPY Preheater Cement Kiln	Wet FGD	90	10735-63761	2005	1
300000 TPY Preheater Cement Kiln	Dry FGD	90	12675-72834	2005	1
600000 TPY Preheater Cement Kiln	Dry FGD	90	11223-71383	2005	1
1200000 TPY Preheater Cement Kiln	Dry FGD	90	11240-70657	2005	1
500000 TPY Long Dry Cement Kiln	AFGD	95	860	2009	2
Refinery FCCU	Catalyst additives	35 - 50	$ 1,096 - $1,889	2006	3
Refinery FCCU	Wet gas scrubbers	95 - 99.9	$ 499 - 880	1999	4
Refinery process heaters	Scrubbers	90 to 99.9	7,674 to 45,384	2005	5

Sources:

1. MACTEC, Midwest Regional Planning Organization (RPO) Cement Best Available Retrofit Technology (BART) Engineering Analysis, Prepared for The Lake Michigan Air Directors Consortium (LADCO), March 2005
2. Staudt, J., "Costs of Emission Control Technologies", presentation to Lake Michigan Air Directors Consortium (LADCO), ICAC-LADCO Meeting
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3.4.4 Opportunities for Low Cost SO$_2$ Reduction on Facilities with Existing PM Control Devices

There are many industrial sources that have existing PM control devices, such as fabric filters, ESPs or venturi scrubbers. Each of these PM control devices provides the potential opportunity for relatively inexpensive SO$_2$ emission reduction.

Venturi Scrubbers

Facilities that have venturi scrubbers typically also have water treatment systems. For this reason, addition of sodium reagent (caustic soda, soda ash, etc.) to the scrubber may provide a low capital cost approach for reducing SO$_2$ emissions. Table 19 shows that cost of removing SO$_2$ with sodium wet FGD can be under $1000/ton of SO$_2$ reduced, and that includes the cost of the scrubber. For facilities that already have a venturi scrubber, the capital cost would be relatively small by comparison and the principle cost would be the cost of reagent. Therefore, the cost of control of SO$_2$, neglecting water treatment costs, would be well under $1,000/ton of SO$_2$ reduced; however, that is subject to the cost of reagent, which can be volatile.

ESPs and Fabric Filters.

Many industrial process facilities identified in this report are currently equipped with ESPs or fabric filter systems. Since retrofit of DSI is relatively inexpensive, the potential cost associated with using DSI on these facilities was assessed. To this end, the data for Figures 21a and b was plotted differently in Figure 22a to show the relationship between the cost of SO$_2$ reduction by DSI using trona or SBC with the uncontrolled SO$_2$ emission rate in lbs/hr in the gas stream. As shown, for many units emitting about a half a ton of SO$_2$ an hour or more, SO$_2$ can be reduced at a cost of roughly $1000/ton or less and under $2000/ton for nearly all cases. The fact that the points don't plot as a smooth curve is the result of calculations using different coals, having different gas flows per unit of heat input. In any event, the trend toward lower cost in $/ton removed as uncontrolled SO$_2$ level increases is readily apparent. Figure 22b has the data from Figure 21 c plotted in a similar manner demonstrating the relationship between the cost of SO2 removal in $/ton versus the uncontrolled SO2 emissions rate in lb/hr using trona injected upstream of a fabric filter. One set of data shows the results with an existing fabric filter and the other shows the results when a new fabric filter must be installed.   When the uncontrolled SO2

rate is about a half ton per hour or more, SO2 appears to be captured at about $1000/ton or less if there is an existing fabric filter and roughly $2000/ton or less if a fabric filter must be added.

Depending upon specific process conditions, such as gas temperatures, the performance may differ somewhat from what is shown in these figures.

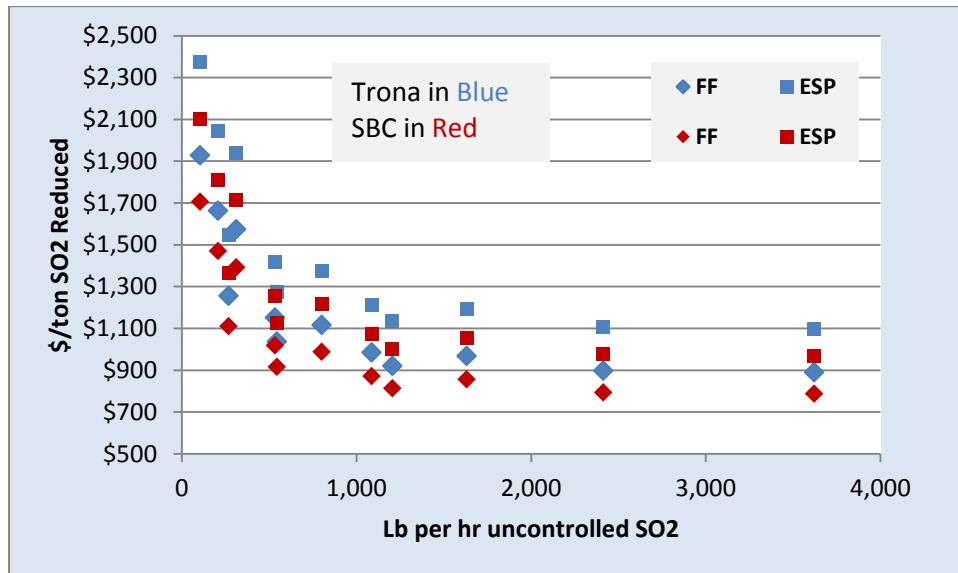**Figure 21**. $/ton of SO_2 Removed versus lb/hr uncontrolled SO_2 for DSI Systems with Existing Downstream PM Control Device
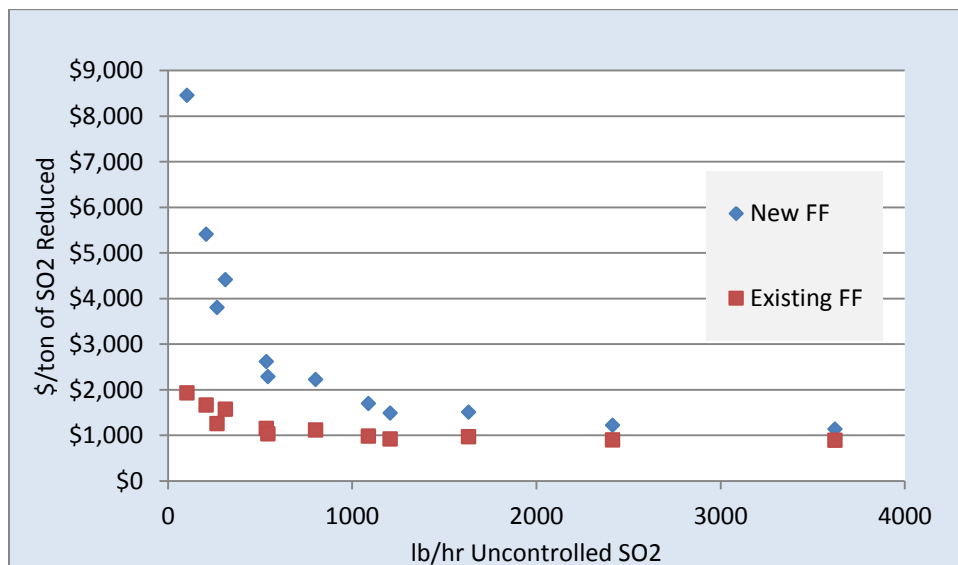

Figure 22. $/ton of SO_2 Removed versus lb/hr uncontrolled SO_2 for DSI Systems with Downstream Fabric Filter (FF)

Chapter Four - Other Methods for Mitigating the Effects of SO$_2$ Emissions

Aside from reducing SO$_2$ emissions, it is possible to mitigate the effects of SO$_2$ emissions at ground level by methods that improve dispersion of SO$_2$ as well as other pollutants or methods that reduce exposure to SO$_2$. Two approaches for improving dispersion of SO$_2$ or for reducing exposure to high SO$_2$ concentrations are as follows:

- *Increased chimney height* – Increasing the chimney height will release the pollutants at a greater height. Dispersion of the pollutant at a greater height will result in lower concentrations at the ground level. Good Engineering Practice (GEP) requires installing a chimney with sufficient height to avoid downwash of pollutants from nearby structures that could result in high pollutant levels at ground. A review of conditions at the site and surrounding area may determine that the height of the existing chimney is inadequate for GEP. If existing chimney height is determined to be too low, it is ideal to increase chimney height to be consistent with GEP.[36]

- *Mitigation of Downwash Effects* – Building downwash is a phenomenon that results in high pollutant concentrations at ground level due to eddies that form from the interaction of prevailing wind that contains pollution and buildings or other structures and these eddies carry pollution that would otherwise be dispersed at altitude down to ground level. Figure 23 shows the three dimensional effects of eddy flow around a rectangular block building.[36] Building downwash may be mitigated by increasing stack height. If this is not possible, building downwash may be mitigated by the re-design of a building or nearby structure that affects the downwash; however, this may be costly. If other methods are not effective or are deemed too costly to mitigate the cause of high SO$_2$ at ground level resulting from building downwash, limiting access to the high pollutant area with a fence may be the most effective way of preventing exposure to areas of high pollutant concentrations that result from building downwash. This is consistent with EPA's definition of ambient air (i.e., according to 40 CFR 50.1(e), ambient air is defined as that portion of the atmosphere, external to buildings, to which the general public has access). Under EPA's interpretation of this definition (as documented in policy memos),[37] the national ambient air quality standards would not apply with respect to a company's impact on their property where public access is restricted.

These approaches can be assessed through air modeling of the area to determine the proper chimney height, building modification or the area that needs to be isolated.

Figure 23. Depiction of flow around a rectangular block[36]
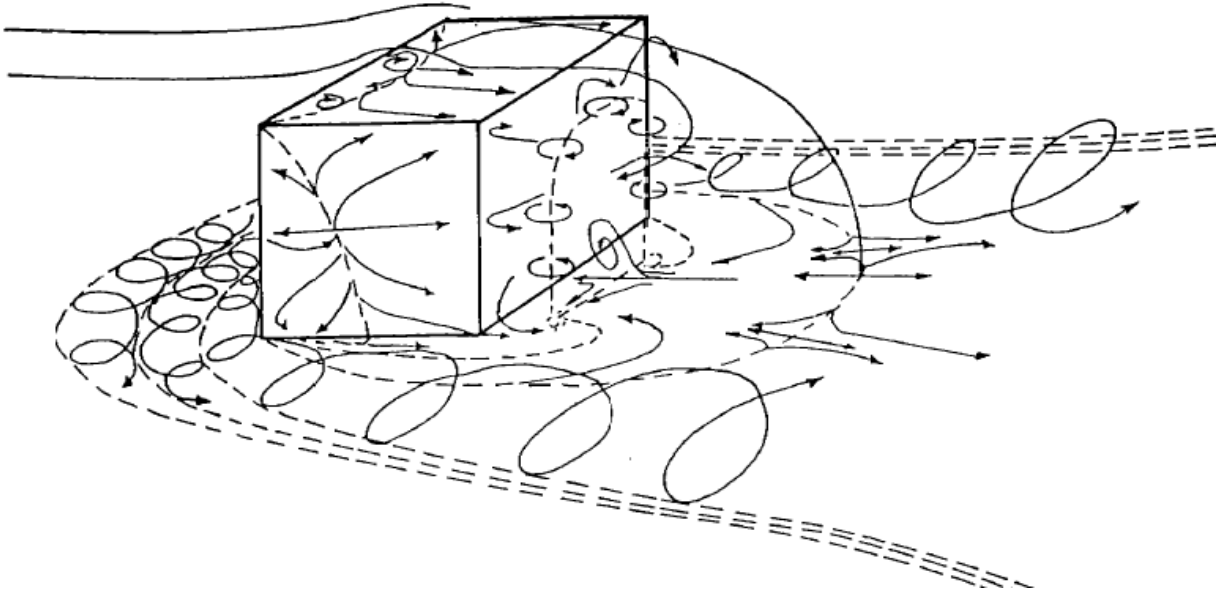
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[6] Email from James Luppens, USGS, October 6, 2011

[7] Energy Information Administration, http://www.eia.gov/dnav/pet/pet_cons_821use_dcu_nus_a.htm,, September 23, 2011, The EIA Data does not identify a "Institutional" user category. This presumably is included in the Commercial or Industrial categories

[8] Ozone Transport Commission (OTC) / Lake Michigan Air Directors Consortium (LADCO), "Evaluation of Control Options for Industrial, Commercial and Institutional (ICI) Boilers - Technical Support Document (TSD) - Draft", 5/25/10

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[16] US EPA, AP-42, Chapter 11.3, , Brick And Structural Clay Product Manufacturing

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[19] US EPA, AP-42, Chapter 12.5, Iron and Steel Production

[20] US EPA, AP-42, Chapter 12.5.1 Steel Minimills

[21] US EPA, AP-42, Chapter 12.4, Ferroalloy Production

[22] RTI International, "Taconite Mining and Processing Industry Profile Draft Report", Prepared for Bryan J. Hubbell U.S. Environmental Protection Agency, EPA Contract Number 68-D-99-024, RTI Project Number 7647.002.142, September 2001

[23] US EPA, *National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants - Background Information for Proposed Standards, EPA-453/R-01-005*, January 2001, pp. 4-1, 4-2, It is notable that this reference shows six sinter lines in the LADCO region, two controlled with baghouses, three with scrubbers and one undetermined, yet Table 16 shows only two windboxes. It is unclear why this difference exists. It may be that the emission point for some of these sinter lines are not called the windbox in the database.

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