WESTERN REGIONAL AIR PARTNERSHIP

Stationary Source NOx and PM Emissions in the WRAP Region:

An Initial Assessment of Emissions, Controls, and Air Quality Impacts

Final Report of the WRAP Market Trading Forum

October 1, 2003

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NOTE: Section VI of this report is bound separately and available on the WRAP Web site at http://www.wrapair.org/forums/mtf/nox-pm.html

PREFACE

Regulatory Framework for Tribal Visibility Implementation Plans

The regional haze rule explicitly recognizes the authority of tribes to implement the provisions of the rule, in accordance with principles of federal Indian law, and as provided by the Clean Air Act §301(d) and the tribal authority rule (TAR) (40 CFR §§49.1– .11). Those provisions create the following framework:

1. Absent special circumstances, reservation lands are not subject to state jurisdiction.
2. Federally recognized tribes may apply for and receive delegation[1] of federal authority to implement CAA programs, including visibility regulation, or "reasonably severable" elements of such programs (40 CFR §§49.3, 49.7). The mechanism for this delegation is a tribal implementation plan (TIP). A reasonably severable element is one that is not integrally related to program elements that are not included in the plan submittal, and is consistent with applicable statutory and regulatory requirements.
3. The regional haze rule expressly provides that tribal visibility programs are "not dependent on the strategies selected by the state or states in which the tribe is located" (64. Fed. Reg. 35756), and that the authority to implement §309 TIPs extends to all tribes within the GCVTC region (40 CFR §51.309(d)(12)).
4. The EPA has indicated that under the TAR tribes are not required to submit §309 TIPs by the end of 2003. Rather, they may choose to opt-in to §309 programs at a later date (67 Fed. Reg. 30439).
5. Where a tribe does not seek delegation through a TIP, EPA, as necessary and appropriate, will promulgate a federal implementation plan (FIP) within reasonable timeframes to protect air quality in Indian country (40 CFR §49.11). EPA is committed to consulting with tribes on a government-to-government basis in developing tribe-specific or generally applicable TIPs where necessary (See, e.g., 63 Fed. Reg. 7263-64).

The amount of modification, if any, needed for this report to fulfill tribal needs may vary considerably from tribe to tribe. The authors have striven to ensure that all references to tribes in the document are consistent with principles of tribal sovereignty and autonomy as reflected in the above framework. Any inconsistency with this framework is strictly inadvertent and not an attempt to impose requirements on tribes which are not present under existing law.

Tribal Participation in the WRAP

Tribes, along with states and federal agencies, are full partners in the WRAP, having equal representation on the WRAP Board as states. Whether Board members or not, it must be remembered that all tribes are governments, as distinguished from the "stakeholders" (private interest) which participate on Forums and Committees but are not eligible for the Board.

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[1] Tribes also possess a more fundamental source of authority to regulate their environments, based on their inherent authority as sovereign nations, which predates the formation of the United States. However, in the context of air pollution regulation and visibility planning in particular, tribal authority will more likely be based on delegation of federal authority.

Despite this equality of representation on the Board, tribes are very differently situated than states. There are over four hundred federally-recognized tribes in the WRAP region, including Alaska. The sheer number of tribes makes full participation impossible. Moreover, many tribes are faced with pressing environmental, economic, and social issues, and do not have the resources to participate in an effort such as the WRAP, however important its goals may be. These factors necessarily limit the level of tribal input into and endorsement of WRAP products.

The tribal participants in the WRAP, including Board members Forum and Committee members and co-chairs, make their best effort to ensure that WRAP products are in the best interest of the tribes, the environment, and the public. One interest is to ensure that WRAP policies, as implemented by states and tribes, will not constrain the future options of tribes who are not involved in the WRAP. With these considerations and limitations in mind, the tribal participants have joined the state, federal, and private stakeholder interests in approving this report as a consensus document.

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Section VI Bound separately and available at
http://www.wrapair.org/forums/mtf/nox-pm.html

SECTION I:
EXECUTIVE SUMMARY

Background and Purpose

The primary purpose of this report is to provide the information necessary for western states and tribes to fulfill the requirements of Section 309(d)(4)(v) of the U.S. Environmental Protection Agency's (EPA) regional haze rule (40 CFR 51.309). Specifically, the rule states:

> *Provisions for stationary source NOx and PM. The plan submission must include a report which assesses emissions control strategies for stationary source NOx and PM, and the degree of visibility improvement that would result from such strategies. In the report, the State must evaluate and discuss the need to establish emission milestones for NOx and PM to avoid any net increase in these pollutants from stationary sources within the transport region, and to support potential future development and implementation of a multipollutant and possibly multisource market-based program. The plan submission must provide for an implementation plan revision, containing any necessary long-term strategies and BART requirements for stationary source PM and NOx (including enforceable limitations, compliance schedules, and other measures) by no later than December 31, 2008.*

The regional haze rule provides the nine western states within the Grand Canyon Visibility Transport Region (GCVTR) an opportunity to submit state implementation plans (SIPs) containing policies and programs recommended in the final report of the Grand Canyon Visibility Transport Commission (June 1996). Such plans must be submitted by December 31, 2003. GCVTR states electing not to submit SIPs under Section 309 must submit SIPs under Section 308 of the regional haze rule in the 2005-07 time frame. Indian tribes have the option to submit tribal implementation plans (TIPs) under either section at any time. Moreover, the TIPs may include reasonably severable elements of the rule. A map of the WRAP region, mandatory federal Class I areas addressed by the regional haze rule, and WRAP state and tribal members is provided in **Figure I-1**.

A major provision of Section 309 is the control of stationary source sulfur dioxide (SO_2) emissions. The provision quoted above – for a report on stationary sources of NOx and PM – is to ensure that states begin the process of evaluating other pollutants from stationary sources. Hence, this report is meant as a starting point for a potentially multi-year process of evaluating stationary sources and designing further control strategies where appropriate. At a minimum, this process must include the determination of best available retrofit technology (BART) for certain sources[1] and the resulting visibility improvements and may include an alternative (e.g., emissions trading) program achieving greater reasonable progress towards the national visibility goal of no man-made impairment.

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[1] BART-eligible sources are those which belong to one of 26 industrial categories, have the potential to emit at least 250 tons per year of a visibility-impairing pollutant, and were put into place between 1962 and 1977.

Organization of Report

This report is required for the GCVTR states choosing to submit SIPs under Section 309 of the region haze rule, but since all states must ultimately address stationary source NOx and PM emissions from BART-eligible and potentially other stationary sources, the scope of this report goes somewhat beyond the nine states in the GCVTR and the limited number of BART-eligible sources in the WRAP region. For example, the air quality modeling evaluates the impact of emission changes within the GCVTR, but at all Class I areas within the contiguous WRAP region. Also, emission control technologies evaluated in Section VI were chosen on the basis of source types throughout the WRAP region, which do not differ substantially from those types within the GCVTR. They were also chosen on the basis of all existing source types, not just BART-eligible source types, partly because sources eligible for BART as a result of pollutants other than SO_2 have not yet been identified[2] and partly because an alternative program to BART could apply to a much broader universe of sources. By extending the scope of this report beyond the nine GCVTR states and beyond the BART-eligible stationary sources, it not only becomes applicable to a wider range of WRAP members and potential control strategies but serves to coordinate regional development of such strategies. It is also a more cost-effective approach than dealing with the nine GCVTR states separately.

As noted above, this report contains analyses and information to initiate a process for evaluating stationary sources of NOx and PM – a process required of all states and open to Indian tribes as well. The Executive Summary contains highlights of the report, but it is also where specific issues raised in Section 309(d)(4)(v), such as interpollutant trading, are directly and succinctly discussed. This is intended to help Section 309 states and tribes address the literal requirements of the rule.

Table I-1 shows how analyses within this report were designed to address the specific requirements of the rule. Emissions data can be used to assess emission control strategies and to evaluate the need for milestones by illustrating the relative significance of different source categories to total NOx and PM emissions, both now and in the future. Ambient monitoring data can be used to assess emission control strategies by illustrating where and how much nitrate and primary PM may contribute to actual visibility impairment. The conceptual model is intended to support this entire assessment and to provide a common, scientifically-founded understanding of western haze and the role of stationary sources in anticipation of a multi-year assessment of their importance and control options. The conceptual model is intended to provide a more complete framework than what can be provided alone by the air quality modeling and other assessments. Air quality modeling is used in a "sensitivity capacity" to assess emission control strategies, their degree of visibility improvement, and the need for milestones to prevent any future increase in emissions. A summary of current NOx and PM control technologies and their costs, trends, and secondary and multi-pollutant impacts can be used to assess emission control technologies and the need for milestones to support multisource and multipollutant programs. This summary is also a useful starting point for addressing the BART requirements in Section 308 SIPs and Section 309 SIP revisions. All these analyses are expected to be updated and improved by the WRAP before such SIPs are adopted.

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[2] The full universe of BART-eligible sources does not need to be identified until SIPs and SIP revisions are due in 2005-08, although this identification process is expected to begin in 2003.

Table I-1. Analyses Contained in this Report and Their Relation to the Requirements in Section 309(d)(4)(v) of the Regional Haze Rule.

Requirements of 309(d)(4)(v)	Emissions Data	Ambient Data	Conceptual Model	Air Quality Model	Control Technologies
Assess emission control strategies	X	X	X	X	X
Assess degree of visibility improvement that would result from such strategies		X	X	X	
Evaluate and discuss the need to establish milestones to avoid any net increase	X		X	X	
Evaluate and discuss the need for milestones to support potential future development of multipollutant and multisource market-based programs			X		X
Implementation plan revision by December 31, 2008					

Finally, emissions in Alaska are not presented because resources did not permit examination of a second emissions inventory database, nor are air quality modeling results presented for Alaska because the visibility modeling system for Alaska is currently under development. However, ambient monitoring data for Alaska are presented, and the conceptual model and control technology information are applicable as well.

Summary of Findings

Analysis of current and future emissions, ambient monitoring data, and very limited modeling results indicates that stationary source emissions of PM probably cause less than 2 percent of the region's visibility impairment, whereas stationary source NOx emissions result in nitrates[3] that probably cause about 2 to 5 percent of the impairment on the Colorado Plateau[4] and about 10 percent of the impairment in some areas of the Northern Plains, Pacific Northwest, and southern California. These findings may change as emission projections are updated and as ambient monitoring data from new sites is collected and analyzed, and especially as modeling capabilities are improved and as more data become available for the best and worst visibility days.

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[3] NOx emissions may also increase other PM species.

[4] Some of the 20 percent haziest days, however, are dominated by nitrate.

Regardless of this or future regional technical analyses, the remedy embodied in reasonably attributable visibility impairment requirements under the regional haze rule is still available where BART-eligible sources of NOx and PM are found to have direct impact on specific mandatory federal Class I areas. Furthermore, when considering NOx and PM milestones, attention should be given to the reasonable progress goals in the regional haze rule, which generally entail steady and continuing emission reductions and no degradation on the best visibility days. Where stationary source NOx emission reductions are appropriate, substantial reduction may be feasible with commercially-available technologies for about $300 to $1,200 per ton.

Assessment of Emission Control Strategies for Stationary Sources of NOx and PM

Since this report is primarily a starting point for addressing stationary source NOx and PM emissions, the control of which would not be determined until the 2005-08 timeframe, specific emission control strategies including such elements as level of control, applicability, and emissions trading are not addressed. Rather, this report identifies significant issues in assessing and designing such control strategies and provides some preliminary emissions, monitoring, and modeling results.

Stationary source NOx emissions comprise about 25 percent of the WRAP NOx emission inventory. One byproduct of NOx emissions is nitrate aerosols. As described in Section III, during the 20 percent worst days on the Colorado Plateau, nitrate aerosols are responsible for about 6 to 18 percent of the man-made visibility impairment, although on some of these days they are responsible for as much as 40 to 60 percent. At some sites in the Northern Plains, Pacific Northwest, and southern California, nitrate aerosols are responsible for about 40 percent of the man-made visibility impairment during the 20 percent worst days. Assuming the contribution of stationary sources to nitrate is roughly equal to their proportion of the NOx emission inventory, then stationary source NOx emissions might be expected to contribute to about 2-5 percent of the Plateau’s light extinction and to about 10 percent of the extinction in the Northern Plains, Pacific Northwest, and southern California.

Potentially increasing these contributions is the fact that stationary sources have unique emission characteristics which may disproportionately impact visibility (e.g., stack heights, transport distances, and proximity to Class I areas). Also, NOx is known to influence the formation of non-nitrate secondary fine particles, to alter the characteristics of primary coarse particles, and its future significance may depend on future changes in sulfur and ammonia emissions. On the other hand, total NOx emission in the WRAP region are expected to decrease by over 25 percent,[5] primarily as a result of federal controls on mobile sources, and NOx reductions may, in isolated instances, lead to local increases in nitrate concentrations.

To determine the effectiveness of stationary source NOx controls, it is therefore important to have an air quality model that can account for the processes above. The WRAP’s current modeling system, while sufficient for analyzing the regional impact of some emission changes, is not predicting nitrate concentrations well enough to support a decision on whether or not

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[5] Future NOx emissions will, of course, depend on uncertain activity levels (e.g., oil and gas development) and regulatory developments (e.g., new source review reforms).

stationary source NOx controls are an effective way at achieving reasonable progress – the results are simply too uncertain. Several improvements to the modeling system are underway, but until the model produces better nitrate results, other means of assessment will be necessary to determine the appropriate level of NOx control in future SIPs.

Given the model's current performance, its use in this report is limited to the summer months (July through September), when it is performing best for nitrate, but also when nitrate concentrations are lowest. Furthermore, its use is limited to two "sensitivity analyses" – a 50 percent stationary source NOx reduction and a 50 percent stationary source PM_{10} reduction. The purpose of the sensitivity analyses is to gauge how nitrate and other atmospheric constituents might respond to significant changes in emissions, albeit such responses may be conservative given the model's limited application to the July – September time period. Results are summarized in the next part of this Executive Summary and discussed in more detail in Section V of the report.

As advancements are made towards understanding the air quality impacts of stationary source NOx emissions, it is appropriate to investigate the potential level of control that can be achieved, and at what cost. Section VI of this report identifies 34 NOx control technologies. Most of these are commercially available, while others are near-available. Those for coal-fired boilers (by far the largest category of stationary source NOx emissions) typically achieve 30 to 50 percent NOx control at a cost of about \$300 to \$1,200 per ton.[6] Actual costs and emission reductions are highly dependent on boiler type, vintage, and configuration, fuel burned, and existing controls. For these reasons, it is important to have recent, extensive, and reliable data on the emission source population, some of which are lacking in the WRAP inventory, such as current control information, utility boiler heat rates, information on the process producing the emissions (e.g., from natural gas compressor stations), and utilization rates (e.g., from industrial internal combustion engines). Future WRAP emission inventories should include such information.

Visibility impairment may occur when a high portion of the NOx emissions are in the form of (or converted to) nitrogen dioxide gas (NO_2). This may be important in urban hazes and in some coherent plumes, but is typically negligible for regional haze.[7] For this reason, NO_2 is not included in the light extinction budget in the EPA's guidance for tracking reasonable progress.

Stationary source PM_{10} emissions[8] are currently 6 percent of the WRAP PM_{10} inventory and may grow slightly to 7 percent by 2018. However, the WRAP inventory does not yet include wind-blown fugitive dust emissions (currently under development), which will tend to decrease the apparent contribution of stationary source PM_{10} emissions. PM_{10} accounts for nearly all the man-made light extinction, but the amount attributable to primary stationary source emissions is difficult to determine. Since most of the coarse fraction (between 2.5 and 10 microns) is believed to be primary and only some of the fine fraction is believed to be primary, the percent of visibility impairment attributable to coarse particles should approximate the contribution of

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[6] One exception is selective catalytic reduction (SCR), which is capable of achieving 70 to 90+ percent control at costs of approximately \$1,200 to \$2,000 per ton.

[7] See, for example, Watson J., Visibility: Science and Regulation, J. of Air and Waste Manage. Assoc. 52:628.

[8] As explained in Section II of this report, the term "PM" used in Section 309(d)(4)(v) of the regional haze rule is construed as primary PM_{10} emissions.

primary PM_{10} emissions from all sources. As shown in Section III, this is approximately 10 to 20 percent (on average) across most of the WRAP region, with generally lower percentages in the Pacific Northwest and higher percentages in the southeast part of the region. Assuming the contribution of stationary sources to ambient primary PM_{10} is roughly equal to their proportion of the PM_{10} emission inventory, then stationary source PM_{10} emissions might be expected to contribute to less than 2 percent of the region's light extinction. Coupled with the fact that stationary source PM_{10} emissions are relatively well controlled in the West, there does not appear to be much potential in a stationary source PM control strategy for purposes of regional haze. PM_{10} emissions, however, appear to have a greater visibility impact per ton than NOx emissions, as shown in Section V. Also, some PM_{10} emission co-benefits may result from multi-pollutant technologies described in Section VI, so reductions in stationary source PM_{10} emissions could conceivably be part of a broader air quality management strategy and/or part of a broader strategy to achieve reasonable progress under the visibility regulations – e.g., to prevent degradation on the cleanest days.

Finally, the appropriate level of stationary source NOx and PM control, if any, should be informed by a comprehensive assessment, which may include some non-visibility impacts (to the extent they can be estimated within WRAP resources and with the WRAP's visibility-based tools) and the full costs and benefits of controls, not just those associated with facility compliance and visibility improvements. To this end, the WRAP is completing work on an economic analysis framework to conduct such analyses in a consistent and technically sound manner.

Degree of Visibility Improvement Resulting from Emission Control Strategies for Stationary Sources of NOx and PM

Due to the complex role of NOx emissions in the atmosphere, a regional-scale modeling effort is underway to more carefully assess the visibility improvement from potential control strategies. Given the model's current performance, its application in this report is limited to the June-September timeframe – when nitrate performance is best, but also when nitrate concentrations are lowest – and it is only used in a "sensitivity analysis mode", meaning two scenarios were modeled to gauge how nitrate and other atmospheric constituents might respond to significant changes in emissions: one in which emissions of NOx are reduced by 50 percent (412,000 tpy) from stationary sources in the GCVTR with emissions of NOx greater than 100 tpy, and an identical scenario for PM_{10} (98,000 tpy).

Current modeling results indicate that the stationary source NOx and PM_{10} emission reductions described above would reduce regional haze (in Mm^{-1}) by 0.5 percent and 0.4 percent, respectively, when averaged across all sites in the GCVTR over the June-September time period, although some areas would see an improvement of 2 to 5 percent on some days.[9] On a purely ton-per-ton basis, reductions in stationary source PM_{10} emissions appear to yield greater regional haze benefits than reductions in NOx emissions, since they produced almost the same visibility benefit at one-fourth the emission change.

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[9] These results are similar to the more general assessment made in Section IV (see page IV-21).

The NOx emission reductions had the greatest impact in southern CA, where ammonium nitrate concentrations in Class I areas are predicted to decrease by 0.15 to 0.25 ug/m^3. A second area of reductions is predicted in the central-east Rocky Mountains, especially in north-central CO. Although the reductions are not as large as in southern CA (0.04 to 0.11 ug/m^3), they are larger than average across the domain and exhibit the largest percentage reduction (10 to 20 percent).

It is interesting to compare these results with those simulating the effects of the SO_2 backstop emissions trading program, or Annex. In the case of the Annex, an SO_2 emission reduction of 15 percent (132,000 tons) in the GCVTR produced a sulfate reduction of 4 percent averaged across all Class I areas in the GCVTR on the 20% worst modeled days. In the case of the NOx sensitivity run, a NOx emission reduction of 15 percent (412,000 tons) in the GCVTR produced a nitrate reduction of 5 percent averaged across all Class I areas in the GCVTR on the July-September modeled days. The nitrate reduction does not produce as much visibility benefit at most Class I areas because its concentrations are much smaller than the sulfate concentrations, but the response of nitrate to NOx reductions is similar in proportion to the response of sulfate to SO_2 reductions.

NOx changes appear to have very little effect on aerosol concentrations beyond changes in nitrate. Other species that could be indirectly affected – e.g., ozone concentrations and subsequent oxidation of SO_2 and organic gases into the particulate phase – do not appear influenced by the levels of NOx reductions (16 percent of the total inventory) assumed in this analysis.

The PM_{10} emission reductions had a maximum impact of about 0.1 to 0.5 ug/m^3, or about 4 to 8 percent. Compared to the NOx reduction scenario, reductions in ambient PM_{10} are more dispersed, with a greater number of local maximums. This may reflect the fact that there are a fewer number of large PM_{10} sources than large NOx sources and that much of the PM_{10} emissions are coarse particles, with shorter transport distances.

All modeling results in this report are subject to change after the modeling improvements described in Section V are implemented. Results may also change when compiled for the best and worst visibility and nitrate days throughout the year, as opposed to a three-month summer average. For reasons described in Section V, the three-month summer average probably tends to reduce the apparent impact of emission changes.

The Need to Establish Milestones to Avoid Any Net Increase in NOx and PM Emissions from Stationary Sources

Sensitivity modeling was also done to evaluate the impacts of a 25 percent simultaneous increase in stationary source NOx and PM_{10} emissions. The increase in nitrate formation was approximately half the magnitude of the decrease resulting from the NOx reduction scenario. However, the increase in PM_{10} (nitrates and primary particulates) and visibility impairment were about the same in the 25 percent increase scenario as in the two 50 percent decrease scenarios because both pollutants were increased simultaneously.

The need to establish milestones to avoid any net increase in NOx and PM emissions from stationary sources should be determined when more complete and accurate modeling results (and ambient data analyses) are available, prior to submittal of the Section 309 SIP revisions in 2007-08. In addition to the modeling results per se, consideration should be given to meeting the reasonable progress goals of the regional haze rule, which generally imply a steady and continuous reduction in emissions and a prevention of degradation on the best visibility days.

The Need for Milestones to Support Potential Future Development of Multipollutant and Multisource Market-Based Program

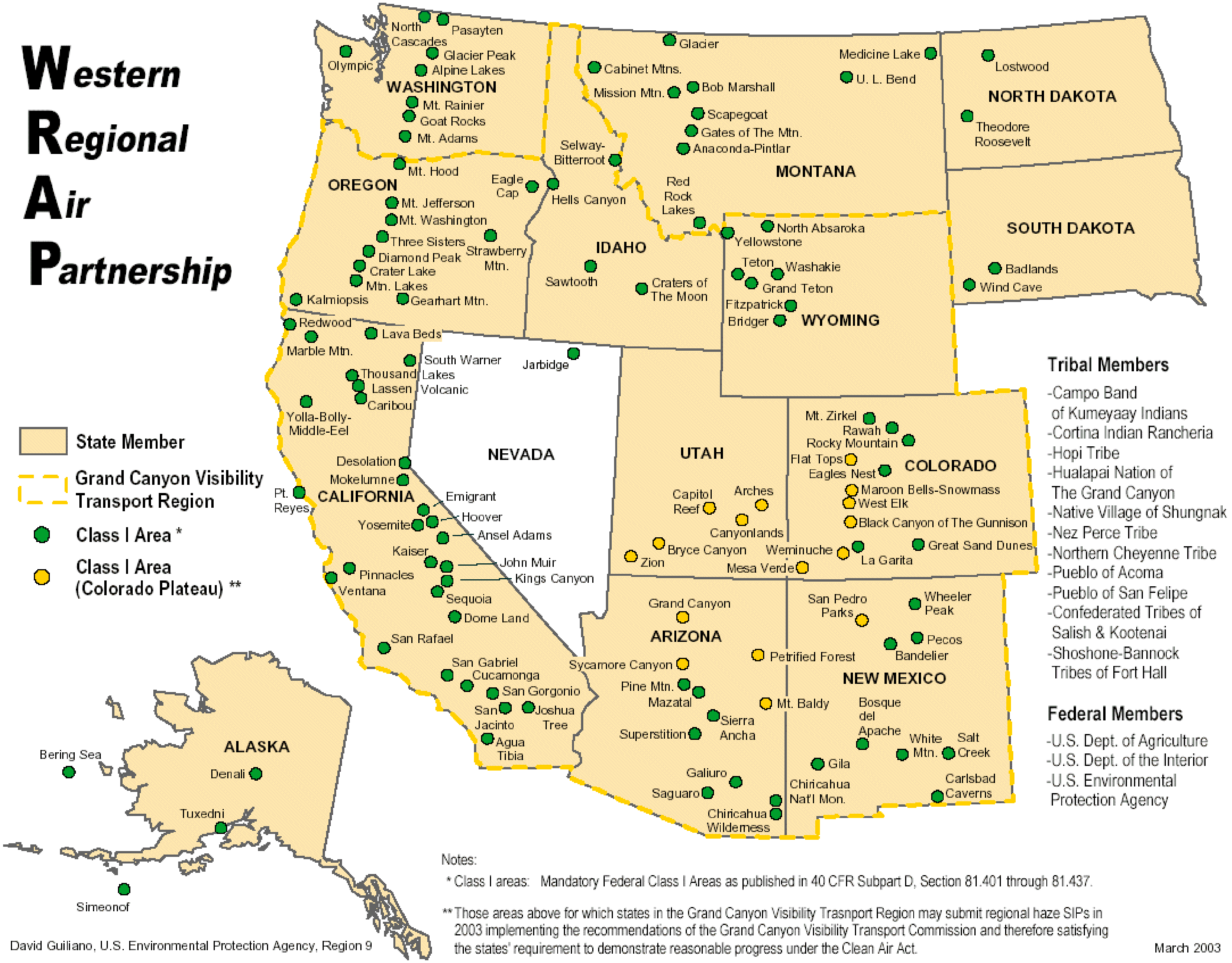
Milestones are not absolutely necessary to support potential multipollutant and multisource market-based programs. For example, a group of sources could theoretically comply with an SO_2 milestone by reducing emissions of other pollutants, and/or in other sectors, for which no milestones exist. Regardless, the key issues raised by such programs do not involve the milestones as much as the uncertainties associated with such emissions trading.

As discussed in Section IV, there are a number issues that must be addressed. Most of these relate to the visibility-improvement value of eliminating a ton of emissions. Different pollutants have different impacts on visibility on a per ton basis. Establishing an “equivalency ratio” to allow X tons of one pollutant to be reduced in lieu of Y tons of another would require significant analysis, and the certainty of such values may be suspect (especially for NOx) or insufficient to ensure a specific level of visibility improvement. Moreover, the equivalency ratio between two pollutants may vary across the region, between seasons, and possibly over time as the composition of the atmosphere changes. These same uncertainties (involving trades among pollutants) also pertain to trades among a single pollutant, most notably NOx, as nitrate concentrations are highly variable by season and location.

Trading across emission source categories poses a couple of additional issues. First, all categories would have to have sufficient emissions monitoring to validate emission credits, and monitoring of non-stationary sources is generally less accurate and verifiable than monitoring of stationary sources. Second, concentrated emissions from stacks may have different impacts than diffuse emissions at ground-level.

The uncertainties identified above could be reduced through further research, and the remaining uncertainties could be further addressed by limiting the emission trading markets to certain subregions, pollutants, or seasons where the equivalency ratios are fairly certain and stable. However, such market restrictions could limit the economic benefits the market is intended to provide. In short, some level of multipollutant and/or multisource market based program could be a feasible way of meeting the long-term national visibility goal, and several of the technologies described in Section VI of this report are capable of multipollutant reductions, but substantially more research should be performed before committing to such programs, especially in the 2007-08 timeframe.

Figure I-1. Map of the WRAP Region, Members, and Mandatory Federal Class I Areas.



Tribal Members

- -Campo Band of Kumeyaay Indians
- -Cortina Indian Rancheria
- -Hopi Tribe
- -Hualapai Nation of The Grand Canyon
- -Native Village of Shungnak
- -Nez Perce Tribe
- -Northern Cheyenne Tribe
- -Pueblo of Acoma
- -Pueblo of San Felipe
- -Confederated Tribes of Salish & Kootenai
- -Shoshone-Bannock Tribes of Fort Hall

Federal Members

- -U.S. Dept. of Agriculture
- -U.S. Dept. of the Interior
- -U.S. Environmental Protection Agency

Notes:

* Class I areas: Mandatory Federal Class I Areas as published in 40 CFR Subpart D, Section 81.401 through 81.437.

** Those areas above for which states in the Grand Canyon Visibility Trasnport Region may submit regional haze SIPs in 2003 implementing the recommendations of the Grand Canyon Visibility Transport Commission and therefore satisfying the states' requirement to demonstrate reasonable progress under the Clean Air Act.

David Guiliano, U.S. Environmental Protection Agency, Region 9

March 2003

SECTION II:
NOx AND PM EMISSIONS FROM STATIONARY SOURCES

Data Sources

The data presented in this section are based on "Version 1" of the WRAP stationary source emission inventory, downloaded from the WRAP website in June 2002 (filename wga_pt96.dbf). A second version of the inventory was released in October 2002, which contained a couple dozen corrections to point source coordinates, stack parameters, and source classification codes among the 214,000 records in the database. There were also some corrections to the NOx and PM emissions, which reduced the regional point source totals by two percent and six percent, respectively. A third version of the inventory was released in March 2003. This version contained minor NOx and PM emission changes in Pima and Navajo Counties (less than one percent of state-wide point sources) and NOx emission reductions in Nevada amounting to a 4,400 ton (or nine percent) decrease in the state-wide point source inventory. Discrepancies noted in Maricopa, Pima, and Pinal Counties by stakeholders in Arizona have not yet been incorporated into the WRAP database.

For the purposes of this regional-scale characterization of NOx and PM sources, the changes made to Version 1 of the stationary source inventory are essentially insignificant. The analysis, therefore, was not repeated. However, the analysis presented in Section VI is based on the most recent inventory since the analysis was begun after the Version 3 was available. This may cause slight discrepancies between the data presented here and in Section VI, but the conclusions are unaffected.

The term "PM" used in Section 309(d)(4)(v) of the regional haze rule has been construed in this report as primary PM_{10} emissions. Precursor emissions are not considered "PM" because they are explicitly referenced where appropriate throughout the rule, as is done with NOx in 309(d)(4)(v). PM_{10} was chosen over $PM_{2.5}$ because PM_{10} includes $PM_{2.5}$ and because all particles less than 10 microns have visibility impairing attributes. Moreover, many of the $PM_{2.5}$ emission estimates are derived from PM_{10} emission factors as opposed to direct $PM_{2.5}$ measurements – i.e., a certain fraction of the PM_{10} is assumed to be $PM_{2.5}$.

Emissions Summary

Table II-1 provides a summary of air pollutant emissions in the 13-state contiguous WRAP region (including Nevada but not Alaska). NOx emissions from stationary sources are expected to increase slightly, but due to decreases from other sources, their percentage of the total inventory is expected to grow from 22 percent to 33 percent to become the single largest source category. Stationary source PM_{10} emissions appear less important than NOx emissions, but they may contribute more to haze on a per ton basis, partly because not all NOx emissions are converted to particles and partly because stationary source PM emissions contain some elemental carbon, which is a highly-efficient light absorber. Compared to other source categories, stationary sources do not emit a large amount of PM_{10}, but their emissions may contribute more to haze on a per ton basis than other source categories because they emit particles primarily in the fine mode (less than 2.5 microns) and often through stacks, making them more likely to be transported to Class I areas. Future work should examine available information on the dispersion characteristics, size distribution, and chemical and optical properties of primary PM emissions from stationary sources relative to other types of sources.

Table II-1. Air Pollutant Emissions in the 13-State WRAP Region.

	1996				2018			
	NOx		PM10		NOx		PM10	
Emissions Category	tons	%	tons	%	tons	%	tons	%
Point	1,059,985	22%	196,005	6%	1,118,460	33%	247,071	7%
Area	352,623	7%	1,921,389	54%	449,559	13%	1,981,060	54%
On-Road Mobile	1,755,573	37%	59,098	2%	485,270	14%	46,139	1%
Off-Road Mobile	1,368,663	29%	103,069	3%	950,414	28%	91,412	2%
Wildfire	166,703	4%	755,537	21%	59,641	2%	270,307	7%
Prescribed Fire	16,688	0%	50,057	1%	338,627	10%	525,393	14%
Agricultural Fire	*	*	*	*	3,504	0%	8,894	0%
Paved Road Dust	0	0%	91,322	3%	0	0%	165,106	5%
Unpaved Road Dust	0	0%	370,762	10%	0	0%	326,042	9%
Total	4,720,236	100%	3,547,239	100%	3,405,475	100%	3,661,423	100%

* Not available

Figure II-1 shows the location and relative magnitude of stationary source NOx emissions in the WRAP region with emissions of NOx greater than 100 tons per year (tpy) on a plant-wide basis. The WRAP 1996 inventory contains over 6,700 point sources of NOx. Approximately 11 percent of these plants (763) emitted 100 tpy or more of NOx and were responsible for 94 percent of total stationary source NOx emissions. Approximately 150 of the plants are electric power plants.

Figure II-2 shows the location and relative magnitude of stationary source PM_{10} emissions in the WRAP region with emissions of PM_{10} greater than 100 tpy on a plant-wide basis. The WRAP 1996 inventory contains over 6,500 point sources of PM_{10}. Approximately 5 percent of these (338 plants) emitted 100 tpy or more of PM_{10} and were responsible for 82 percent of total stationary source PM_{10} emissions.

Figures II-3 and **II-4** identify and compare emissions from the major stationary source categories of NOx and PM_{10}, respectively. External combustion boilers (utility and industrial) are the largest source categories for both NOx and PM_{10}. Industrial internal combustion engines (mostly natural gas fired) is another substantial source of NOx emissions. This category may warrant more attention since it is not inventoried with the same rigor as electric utility sources. The major source categories of PM_{10} are more diverse in character than those for NOx, including such broad categories as mineral products, chemical manufacturing, and primary metal production. This part of the inventory may also warrant further investigation since many of the emissions might be fugitive. Categorization of fugitive emission, in addition to source classifications, may vary across states. Further information on stationary source emissions, especially on the largest sources (boilers and internal combustion engines), is provided in Section VI.

Figure II-1. Stationary Source NOx Emissions > 100 tpy in the WRAP Region (1996).

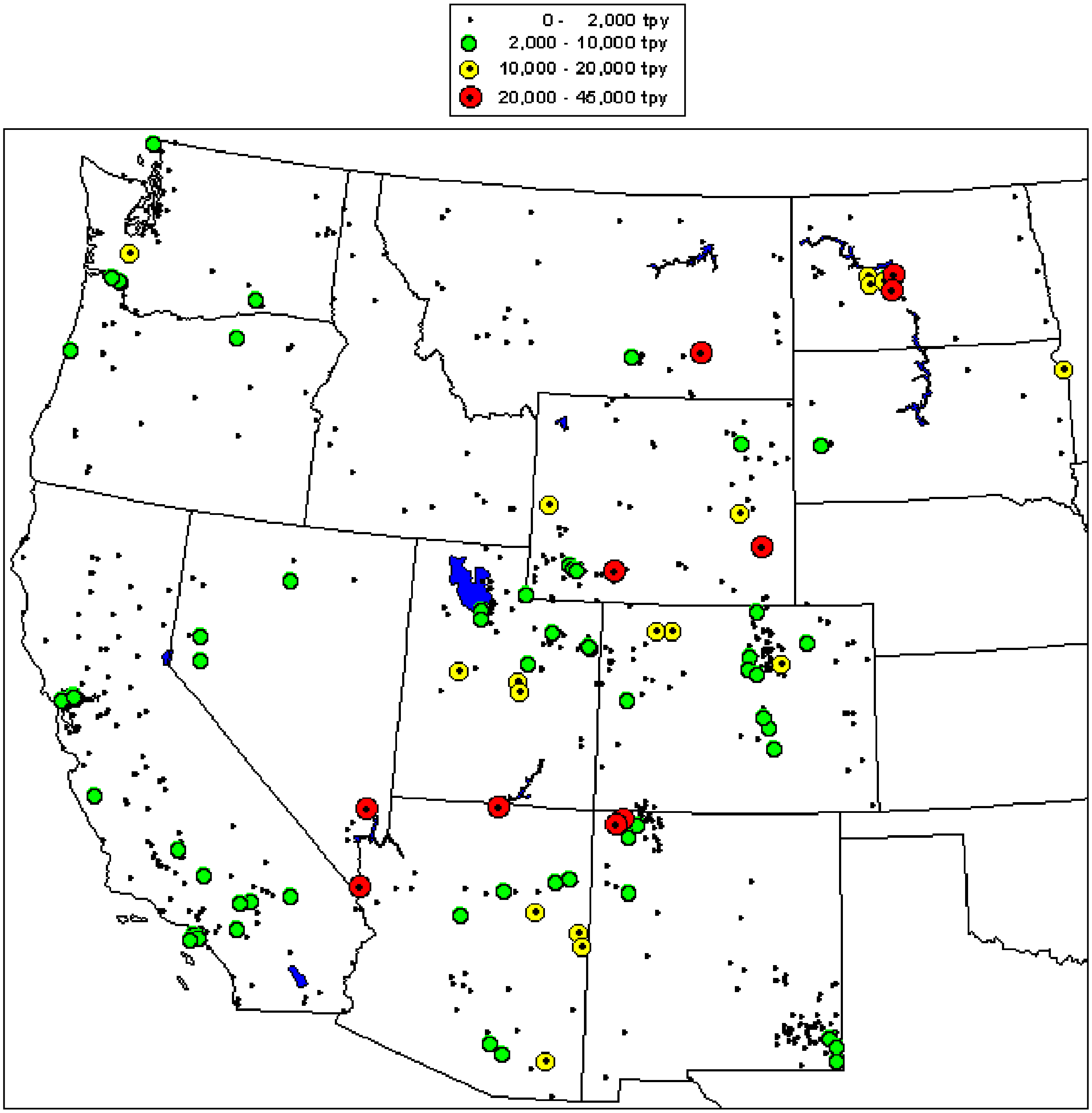


Figure II-2. Stationary PM_{10} Emissions > 100 tpy in the WRAP Region (1996).

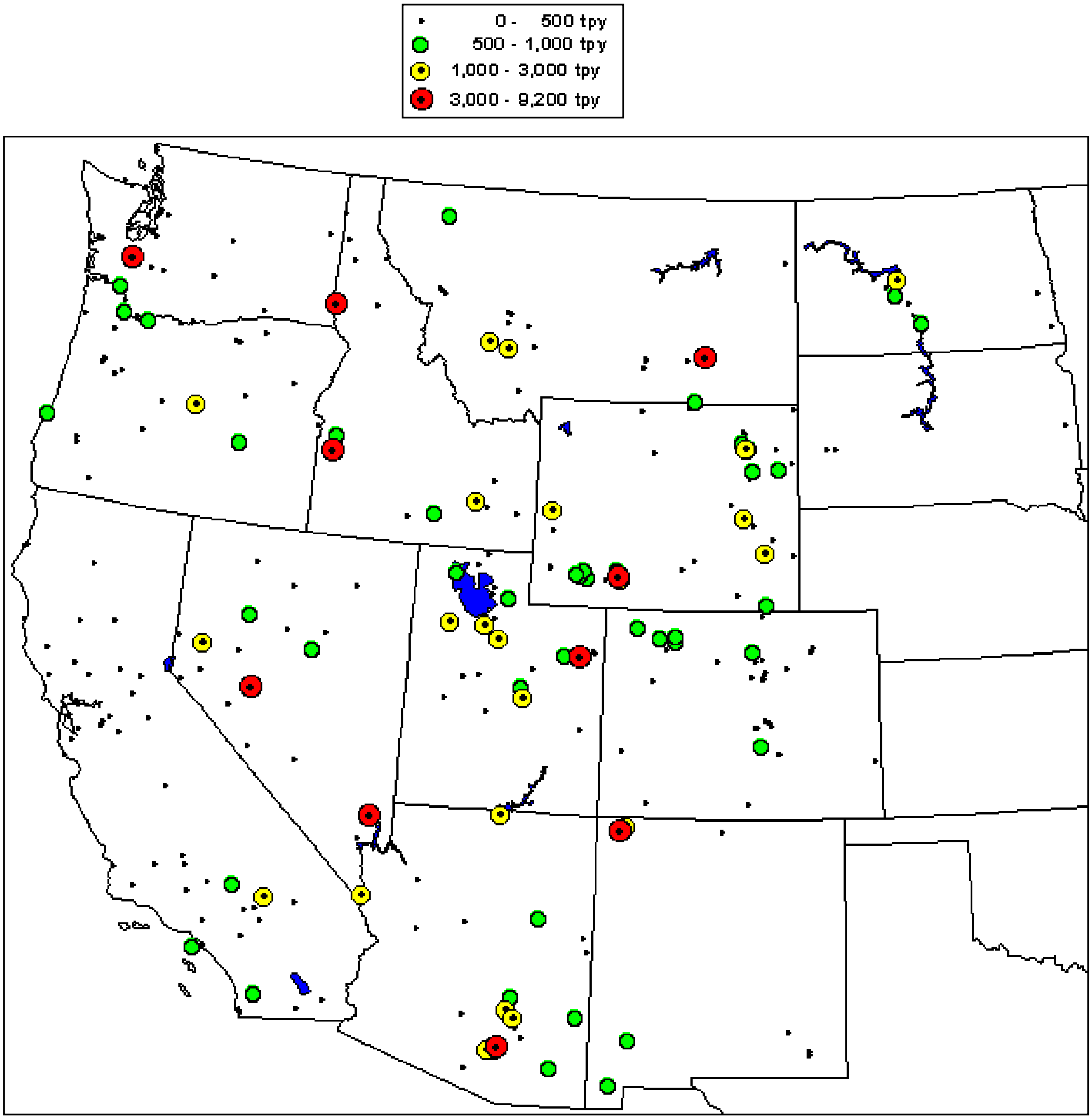


Figure II-3. Categorization of Stationary Source NOx Emissions > 100 tpy in the WRAP Region (1996).

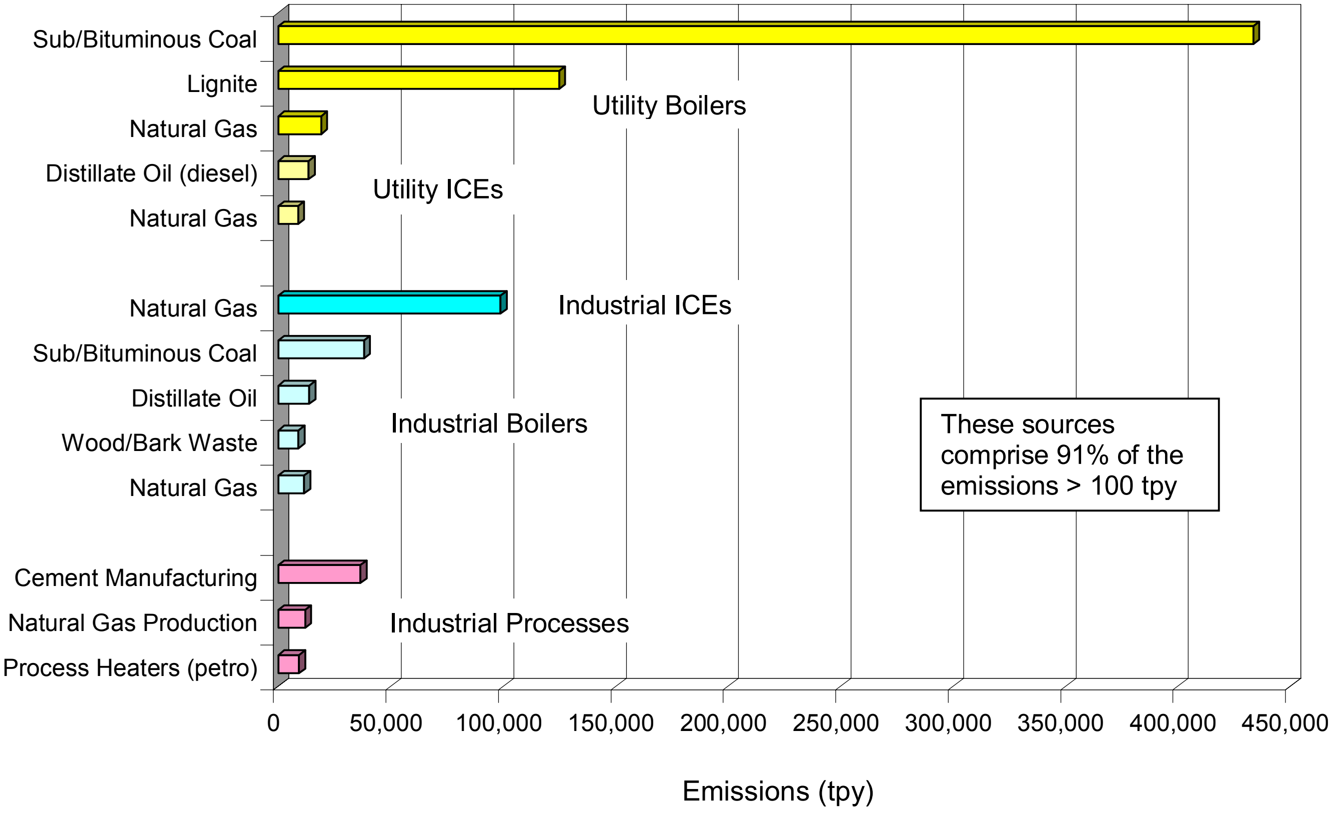
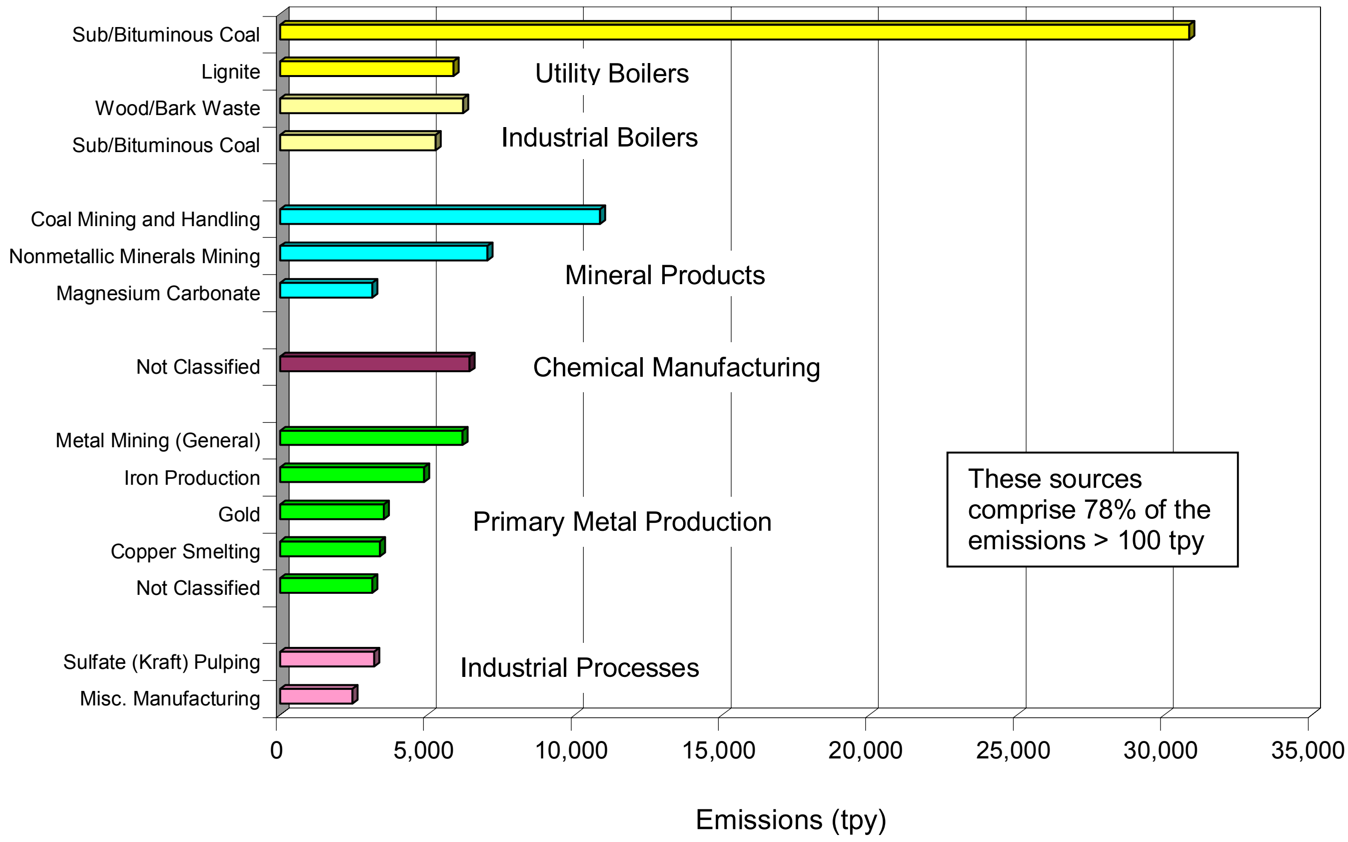


Figure II-4. Categorization of Stationary Source PM_{10} Emissions > 100 tpy in the WRAP Region (1996).



SECTION III:
NITRATE AND PM AMBIENT CONCENTRATIONS

Figures III-1 through III-11 show spatial patterns of ammonium nitrate (NH4NO3) and PM and historical trends in PM at IMPROVE monitoring sites in 1996 and 2001. The maps and data were downloaded from the VIEWS website (http://vista.cira.colostate.edu/views) on May 20, 2003. At that time, maps were only available for annual and seasonal averages, but some are now available for the best and worst visibility days. Hence, all the maps in this section except one indicate annual averages. Also, because the legends are auto-scaled, they are not the same in each map. For example, the value indicated by a yellow contour in Figure III-1 (1996) is not the same as the value indicated by a yellow contour in Figure III-2 (2201).

IMPROVE sites are located in rural settings, typically within Class I areas. They are not representative of more heavily polluted urban areas and tend to represent air quality at regional scales. Due to the size of the IMPROVE monitoring network, the maps for 1996 include data from less than a third of the western Class I areas. The maps for 2001 include data from about two-thirds of the western Class I areas, and additional monitors have been established since then.

Figures III-1 and III-2 show the annual average NH4NO3 concentrations in 1996 and 2001, respectively. Concentrations are typically less than 0.6 ug/m^3, with some areas in southern CA and the Columbia River Gorge exceeding 1.5 ug/m^3.

Figures III-3 and III-4 show the percent of aerosol-caused[10] annual average light extinction due to NH4NO3 in 1996 and 2001, respectively. This percent is typically less than 14, with some higher areas in the Pacific Northwest and Northern Plains, and especially in southern CA (exceeding 20 percent). Since some aerosols – principally organic carbon and "soil" and "coarse" aerosols – have substantially strong natural sources, the percent contribution of NH4NO3 to *man-made* haze is somewhat greater than indicated in Figures III-3 and III-4. A rough estimate of the contribution to man-made impairment can be obtained by assuming half the organic carbon, soil, and coarse aerosols are naturally caused. Removing these natural contributions from the light extinction budgets would raise the percent contribution of NH4NO3 by approximately 20 percent in each of the regions noted above (Colorado Plateau, Pacific Northwest, Northern Plains, and southern California).[11] For example, where NH4NO3 may contribute to 15 percent of the aerosol-caused light extinction in these areas, it would contribute to about 18 percent of the man-made light extinction.

Data recently provided on the VIEWS website indicates that the percent contribution of NH4NO3 to light extinction on the 20 percent worst days, as shown in **Figure III-5**, is slightly greater than the percent contribution on average, as shown in Figure III-4. Moreover, a cursory examination of daily data collected on the Colorado Plateau in 2001 indicates that some of the 20 percent worst days are dominated by NH4NO3. Some examples are provided in **Table III-1**. Such episodes should be quantified and studied more thoroughly in future WRAP work.

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[10] Aerosol-caused light extinction excludes natural (Rayleigh) scattering by air molecules.

[11] See Table 3.3 in Malm, William C. et al., Spatial and Seasonal Patterns and Temporal Variability of Haze and Its Constituents in the United States, Colorado State University, May 2000.

Table III-1. A Sample of Hazy Days in 2001 Dominated by NH4NO3 on the Colorado Plateau.

Class I Area	Date	Light Extinction[a] (Mm^{-1})	NH4NO3 Contribution	2001 Average Light Extinction[a] (Mm^{-1})	2001 Average NH4NO3 Contribution
Bryce Canyon	01/16/01	35	55 %	16	11 %
	01/28/01	28	49 %		
Canyonlands	01/04/01	23	55 %	14	15 %
	01/19/01	31	48 %		
	01/22/01	33	55 %		
San Pedro	01/07/01	16	50 %	11.5	10 %
	02/09/01	14	31 %		
	12/21/01	13	36 %		

[a] Over and above natural (Rayleigh) scattering by air molecules (10 Mm^{-1}).

Finally, NH4NO3 exhibits a strong seasonal pattern. When averaged across the 32 IMPROVE sites operating in 1996-1999, the light extinction due to NH4NO3 is about 10 percent on an annual basis and about 17 percent in the winter.

Figures III-6 and III-7 show the annual average PM_{10} concentrations in 1996 and 2001, respectively. Specifically, the values are reconstructed total mass – that is, speciated fine mass plus gravimetrically-determined coarse mass (PM_{10} - $PM_{2.5}$). (Gravimetric PM_{10} was not available from the VIEWS website.) PM_{10} concentrations are typically below 8 ug/m^3, with some areas in the Columbia River Gorge, Northern Plains, and southern CA exceeding 10 ug/m^3.

Figures III-8 and III-9 show the percent of aerosol-caused annual average light extinction due to coarse particulate matter (between 2.5 and 10 microns) in 1996 and 2001, respectively. Since most of the coarse fraction is believed to be primary and only some of the fine fraction is believed to be primary, the percent of visibility impairment attributable to coarse particles should approximate the contribution of primary PM_{10} emissions from all sources to visibility impairment. As shown in the figures, this is approximately 10 to 20 percent across most of the WRAP region, with generally lower percentages in the Pacific Northwest and higher percentages in the southeast part of the region.

Figure III-10 shows trends in (gravimetric) PM_{10} concentrations during average visibility days at 27 western IMPROVE sites. Data for the best and worst visibility days are available, but only data for average visibility days are shown for comparability with the maps in Figures III-1 through III-7. The values shown are 5-year rolling averages, meaning that the value shown for 1993 represents data collected from 1989-1993. The full names of the sites shown in Figure III-10 are provided in **Table III-2**.

At most sites, there appears to be a gradual decline in PM_{10} concentrations on days with average visibility, with exceptions at Chiricahua, Grand Canyon, and Guadalupe Mountain. On the worst visibility days, however, there is less of a decline, if any, at most sites. Compare, for example, the trend at the sites shown in **Figure III-11** with the first trend chart shown in Figure III-10.

Note that the trends, even when averaged over 5-year periods, can sometimes be affected by one or two extremely high events, typically associated with wildfires or dust storms. Trends in NH4NO3 concentrations and the percent of light extinction due to NH4NO3 are not available because of a measurement bias in data collected prior to June 1996. These data, however, are sufficient for showing the spatial patterns in Figures III-1 through III-7.

Figure III-1. Annual Average NH4NO3 Concentrations at IMPROVE Sites (1996).

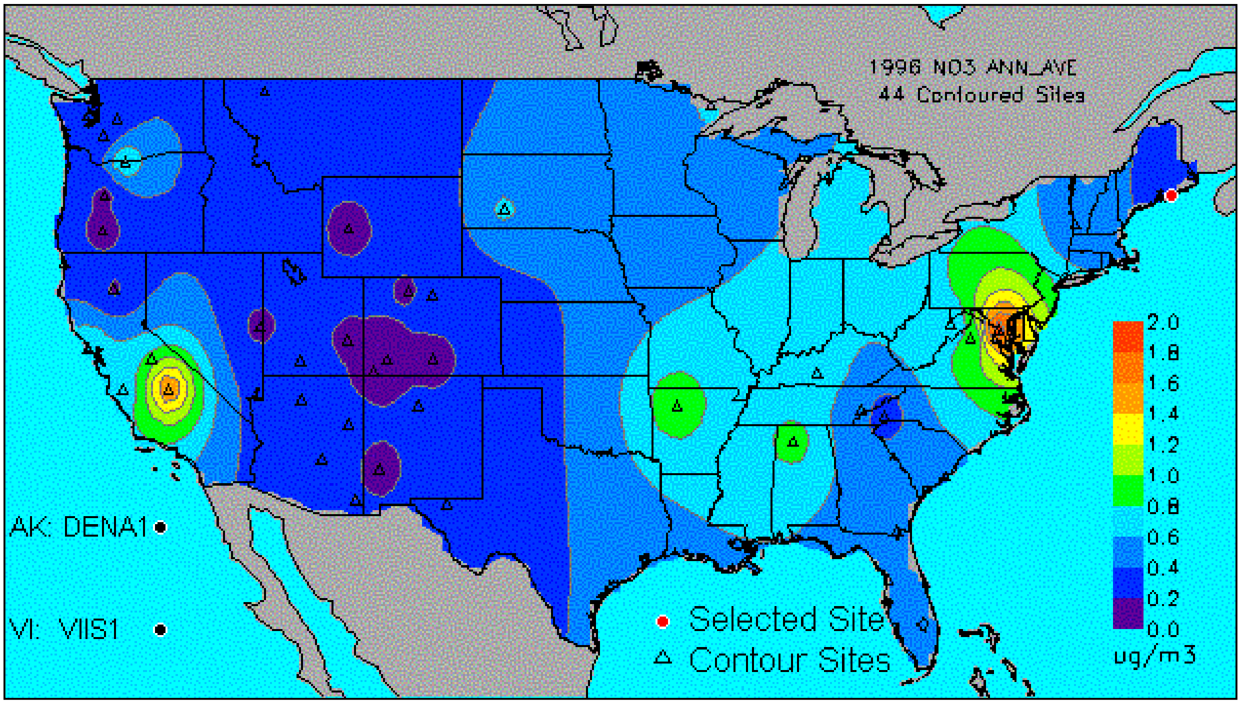


Figure III-2. Annual Average NH4NO3 Concentrations at IMPROVE Sites (2001).

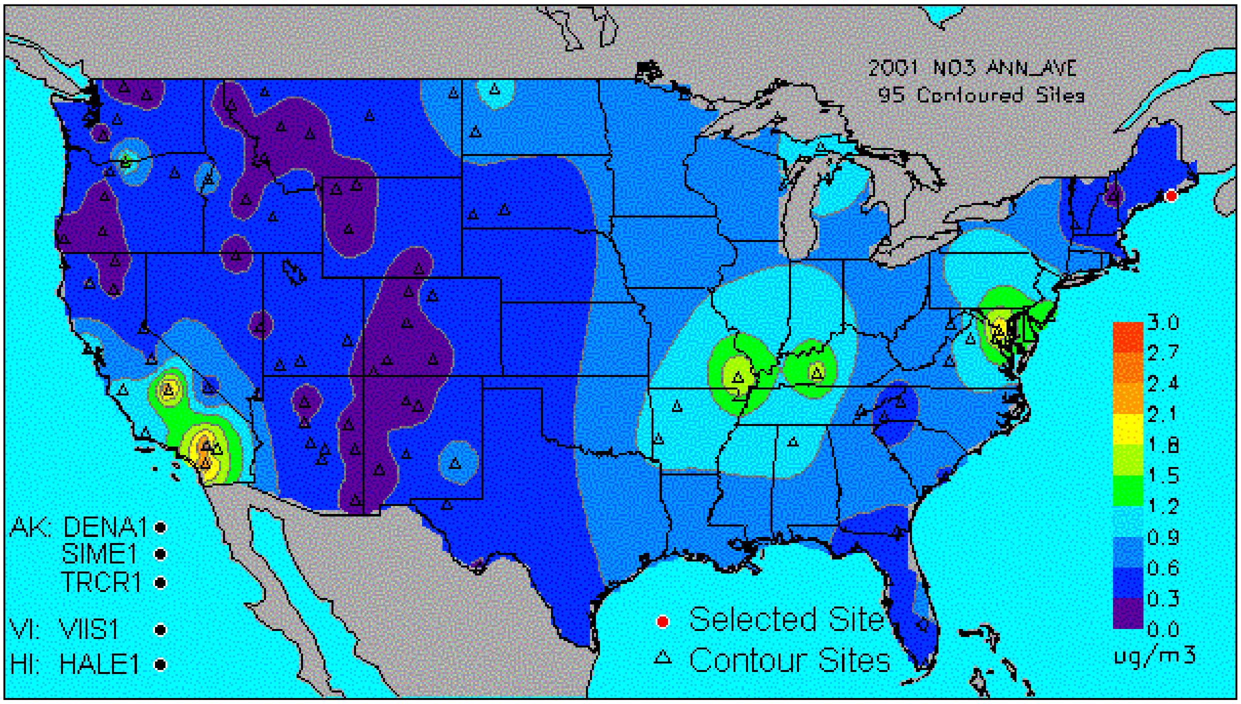


Figure III-3. Percent of Annual Average Aerosol Light Extinction Due to NH4NO3 at IMPROVE Sites (1996).

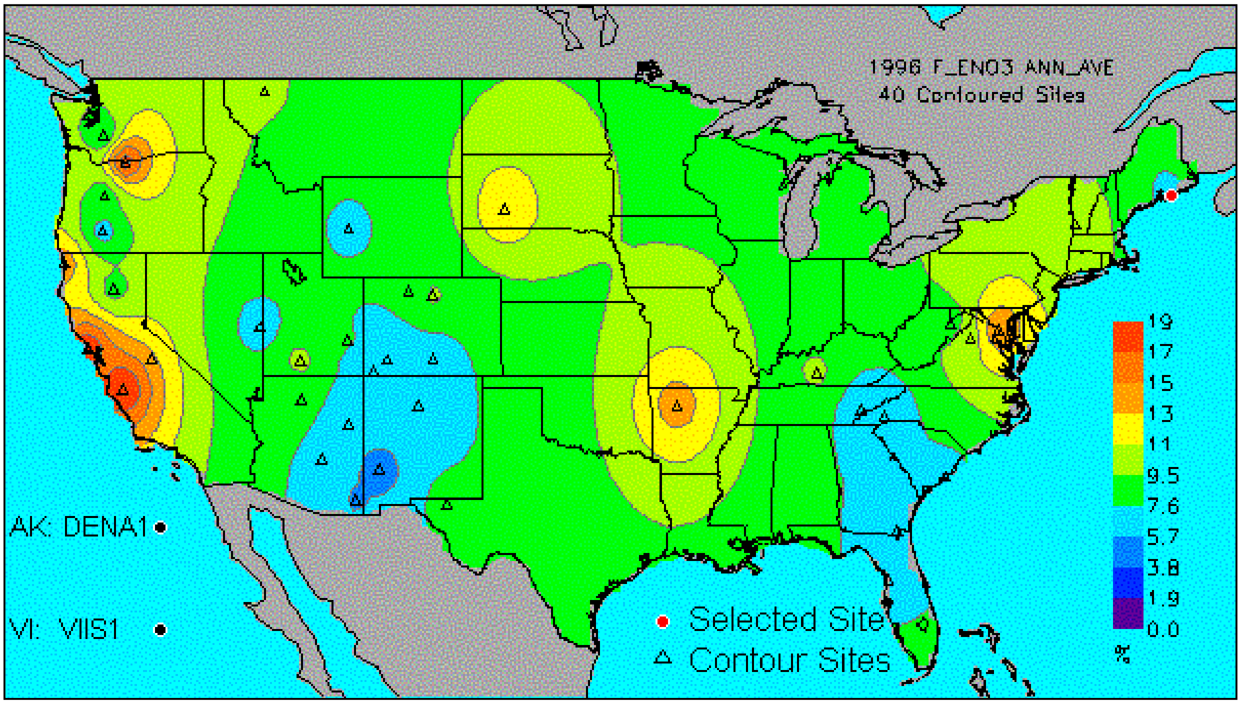


Figure III-4. Percent of Annual Average Aerosol Light Extinction Due to NH4NO3 at IMPROVE Sites (2001).

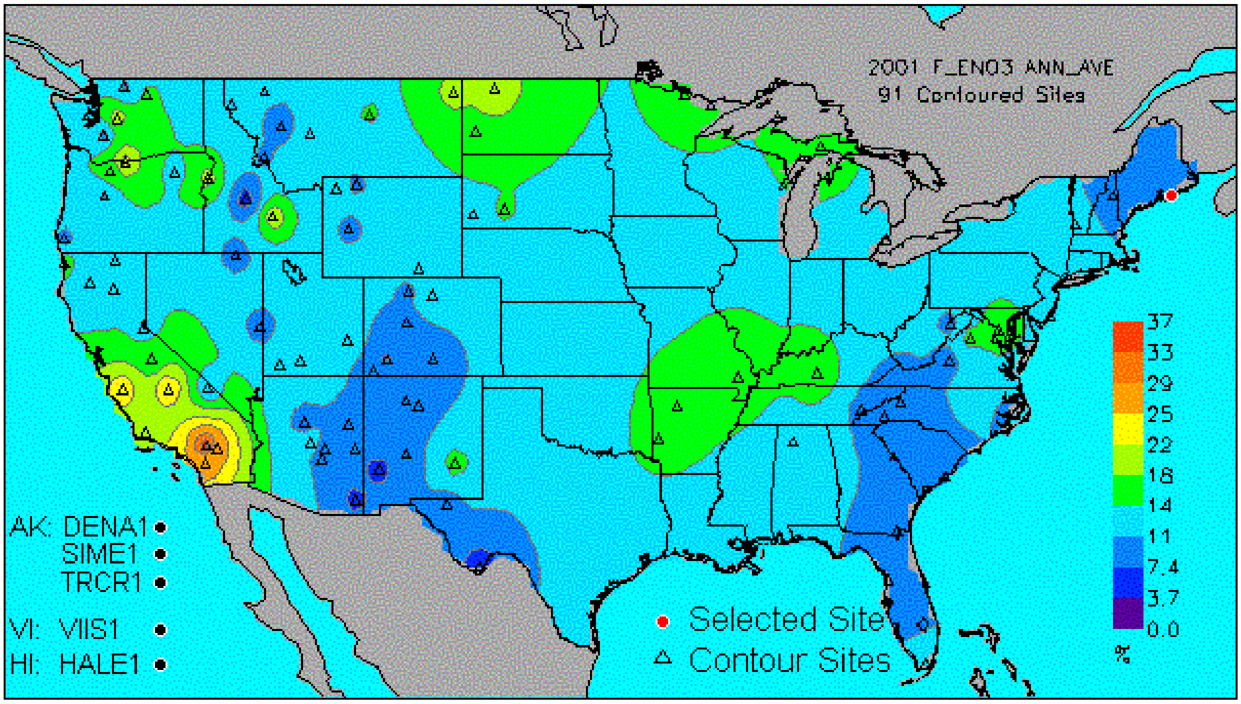


Figure III-5. Percent of Aerosol Light Extinction Due to NH4NO3 at IMPROVE Sites on the 20 Percent Worst Days (2001).

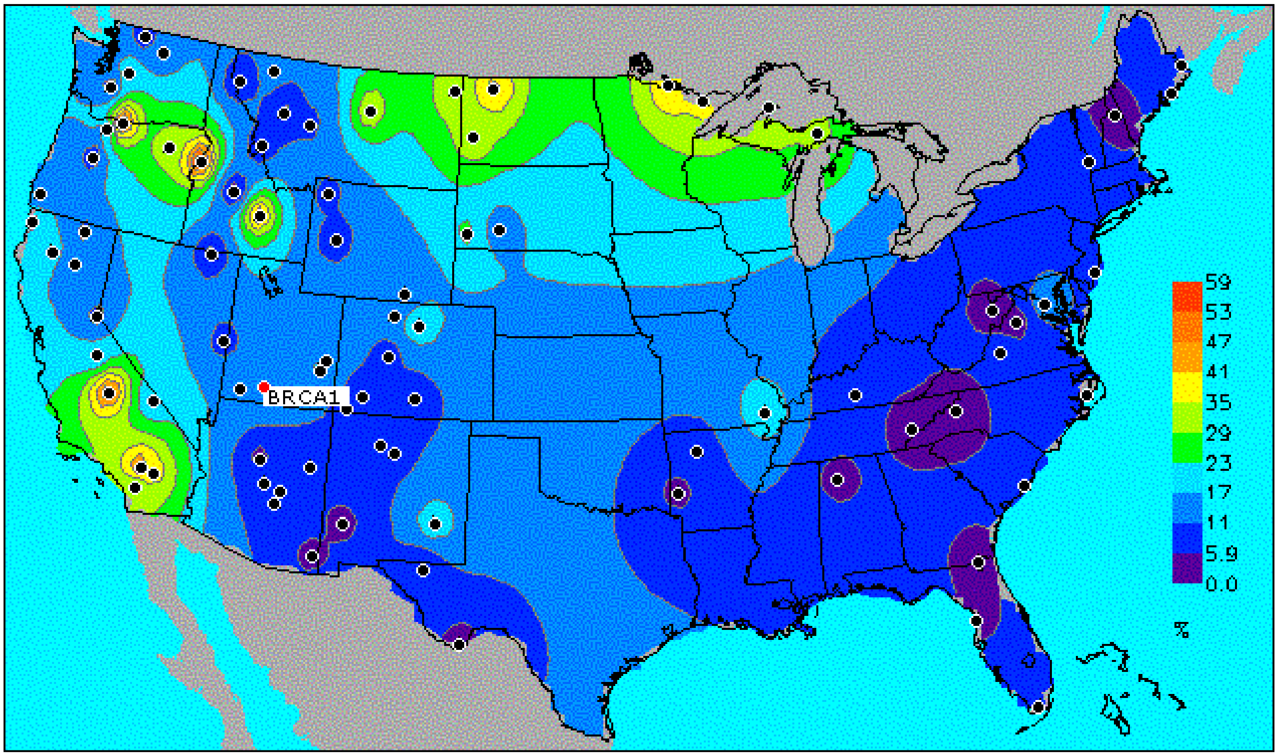


Figure III-6. Annual Average PM_{10} Concentrations at IMPROVE Sites (1996).

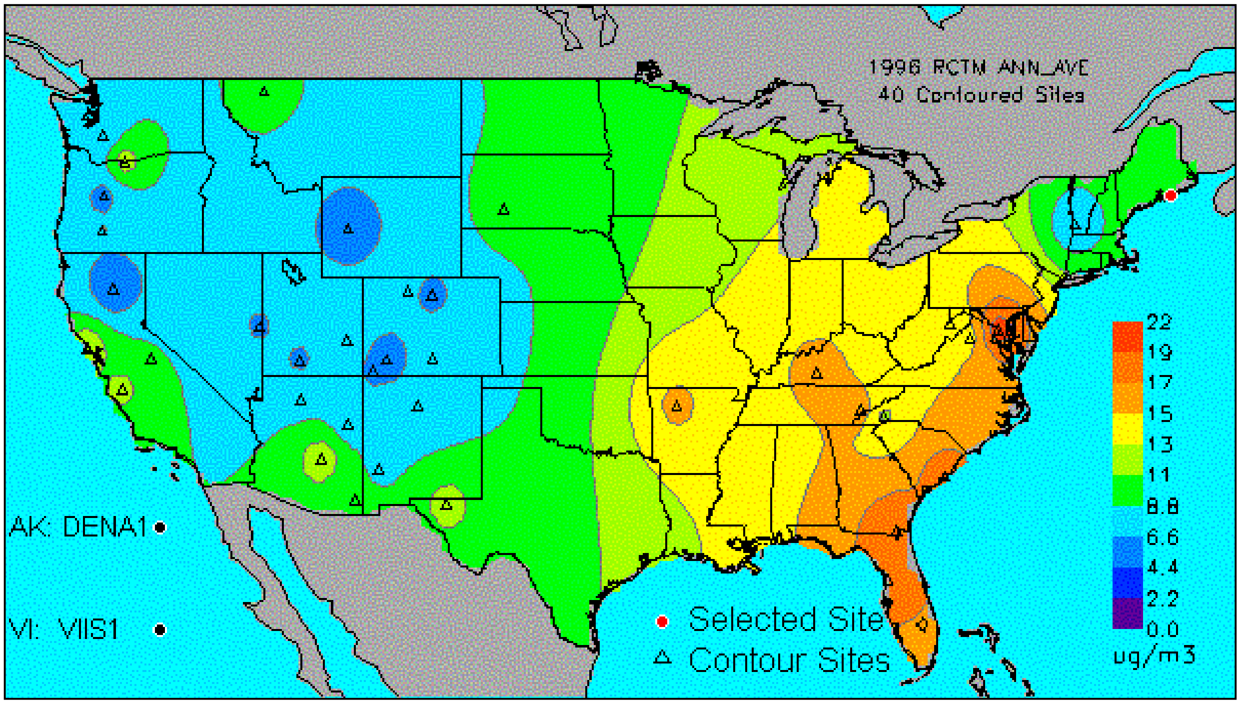


Figure III-7. Annual Average PM_{10} Concentrations at IMPROVE Sites (2001).

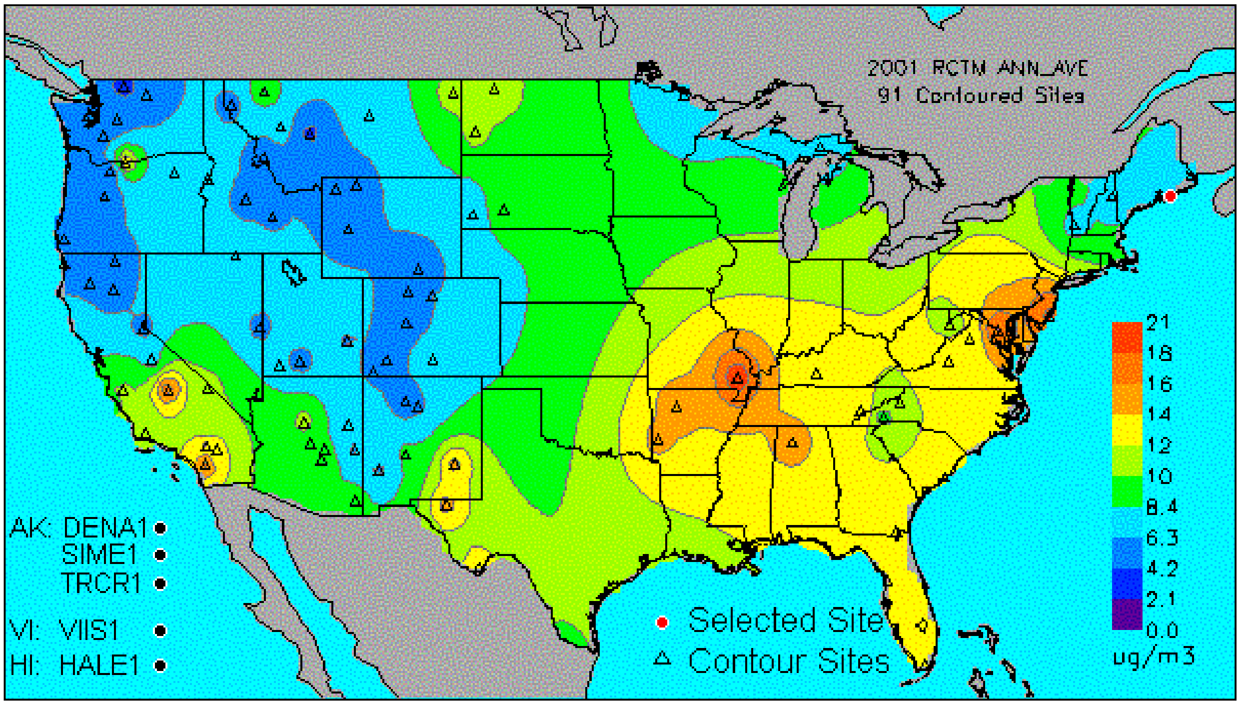


Figure III-8. Percent of Annual Average Light Extinction Due to Coarse Particulate Matter at IMPROVE Sites (1996).

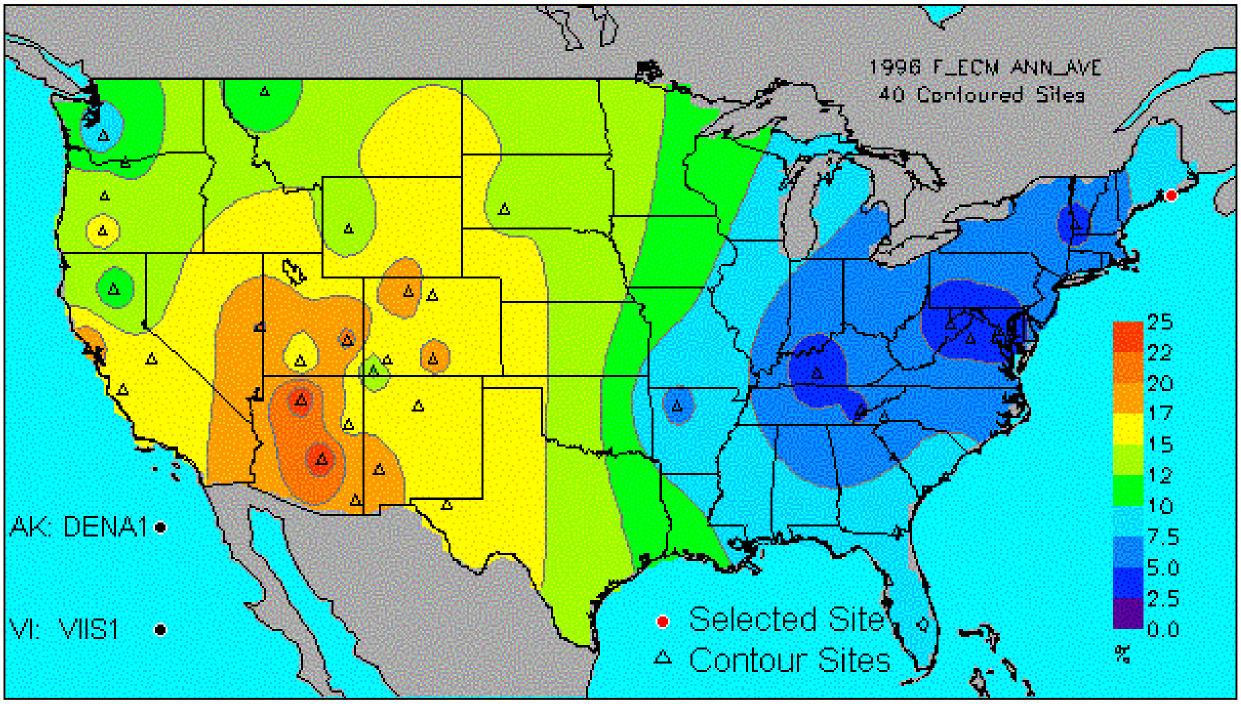


Figure III-9. Percent of Annual Average Light Extinction Due to Coarse Particulate Matter at IMPROVE Sites (2001).

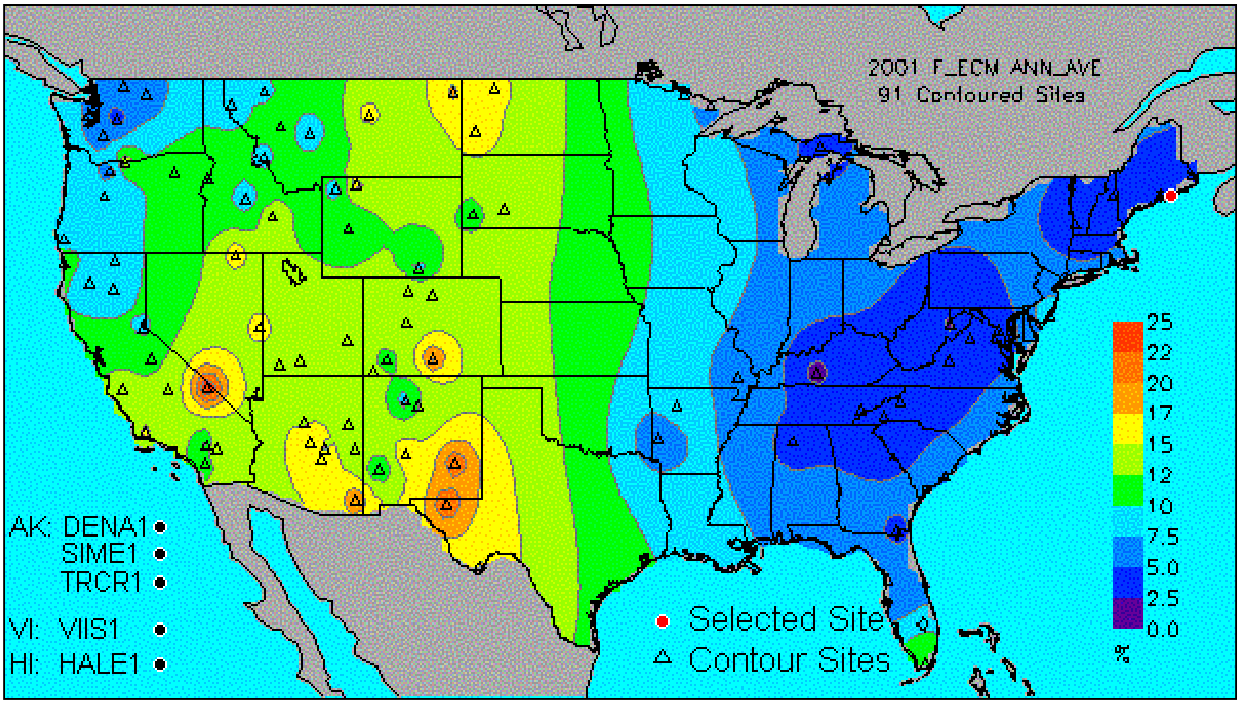
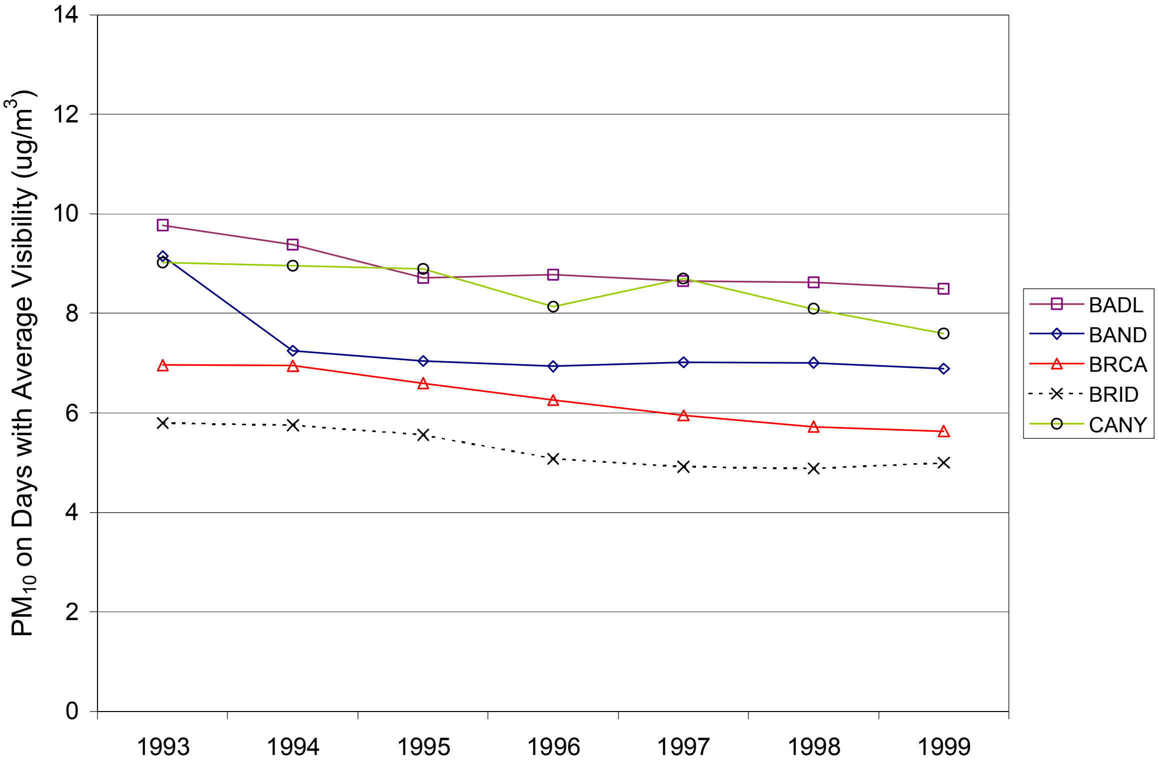
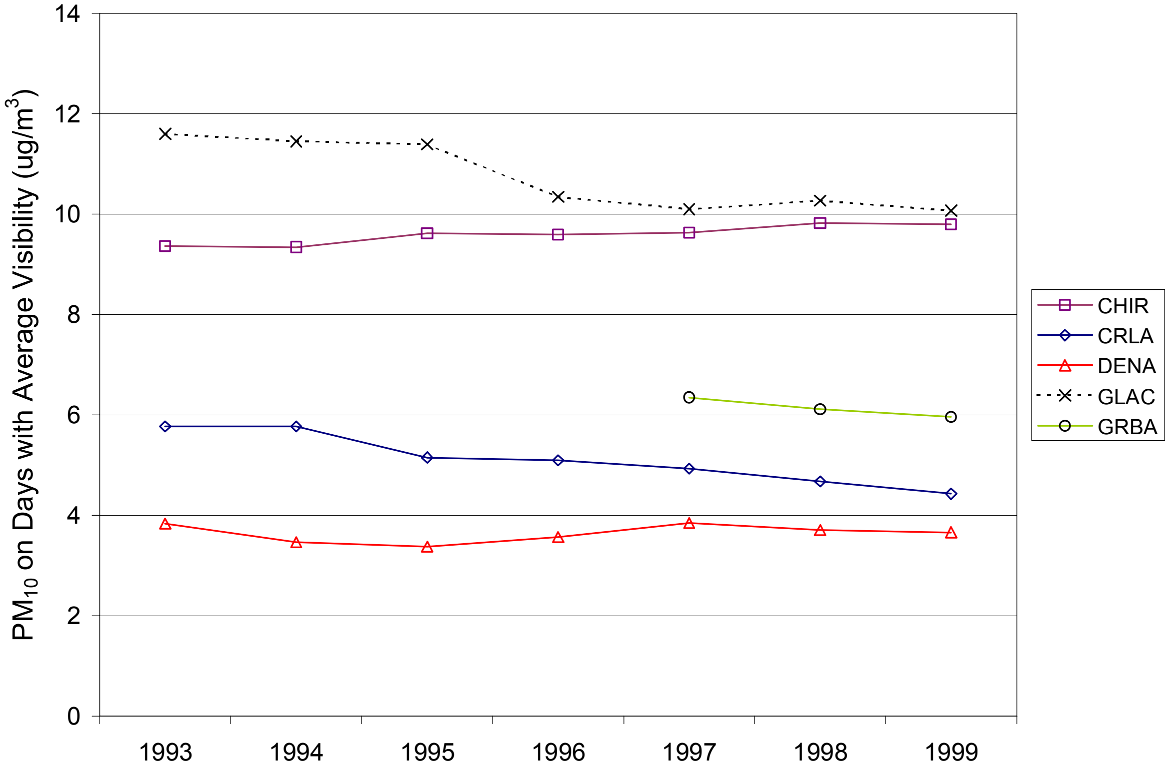


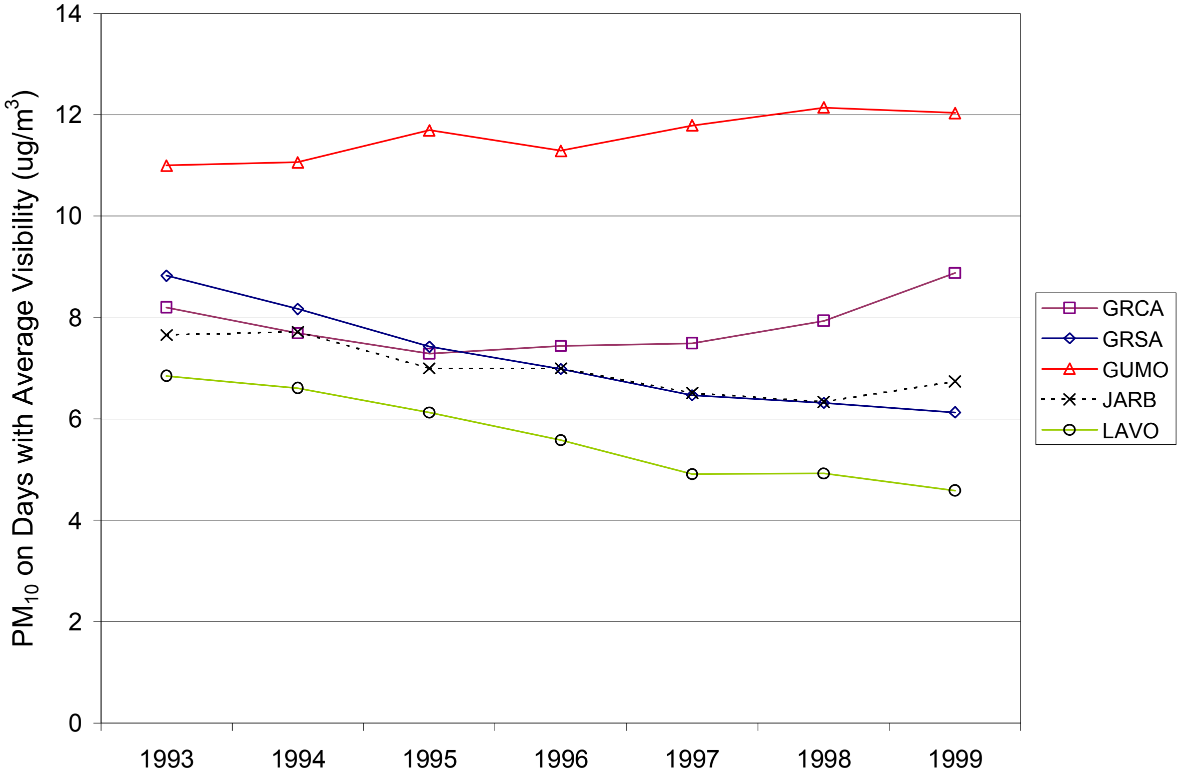
Table III-2. Name of IMPROVE Sites Shown in Figure III-9.

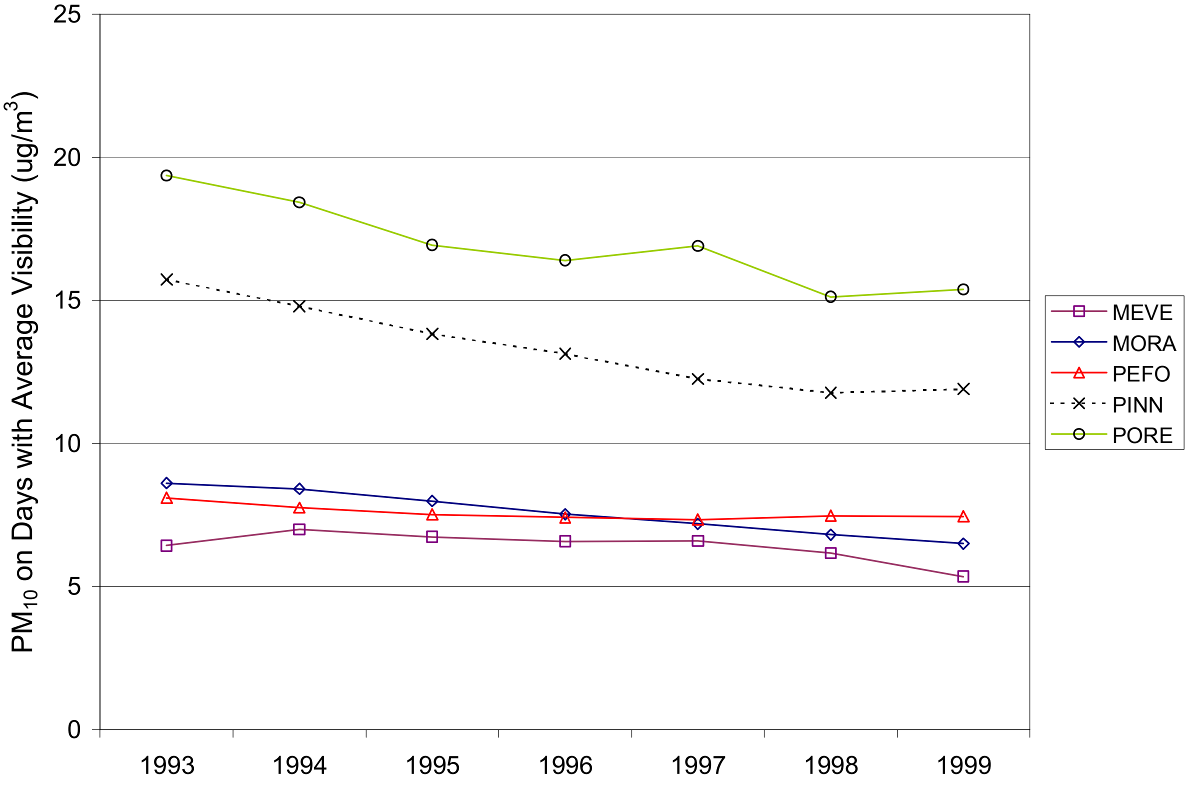
Code	Site Name	Code	Site Name
BADL	Badlands	LAVO	Lassen Volcanic
BAND	Bandalier	MEVE	Mesa Verde
BRCA	Bryce Canyon	MORA	Mount Ranier
BRID	Bridger	PEFO	Petrified Forest
CANY	Canyon Lands	PINN	Pinnacles
CHIR	Chiricahua	PORE	Point Reyes
CRLA	Crater Lake	REDW	Redwood
DENA	Denali	ROMO	Rocky Mountain
GLAC	Glacier	SAGO	San Gorgonio
GRBA	Great Basin	TONT	Tonto
GRCA	Grand Canyon	WEMI	Weminuche
GRSA	Great Sand Dunes	YELL	Yellowstone
GUMO	Guadalupe Mountain	YOSE	Yosemite
JARB	Jarbidge		

Figure III-10. Trends in PM_{10} Concentrations at Western IMPROVE Sites on Days with Average Visibility.

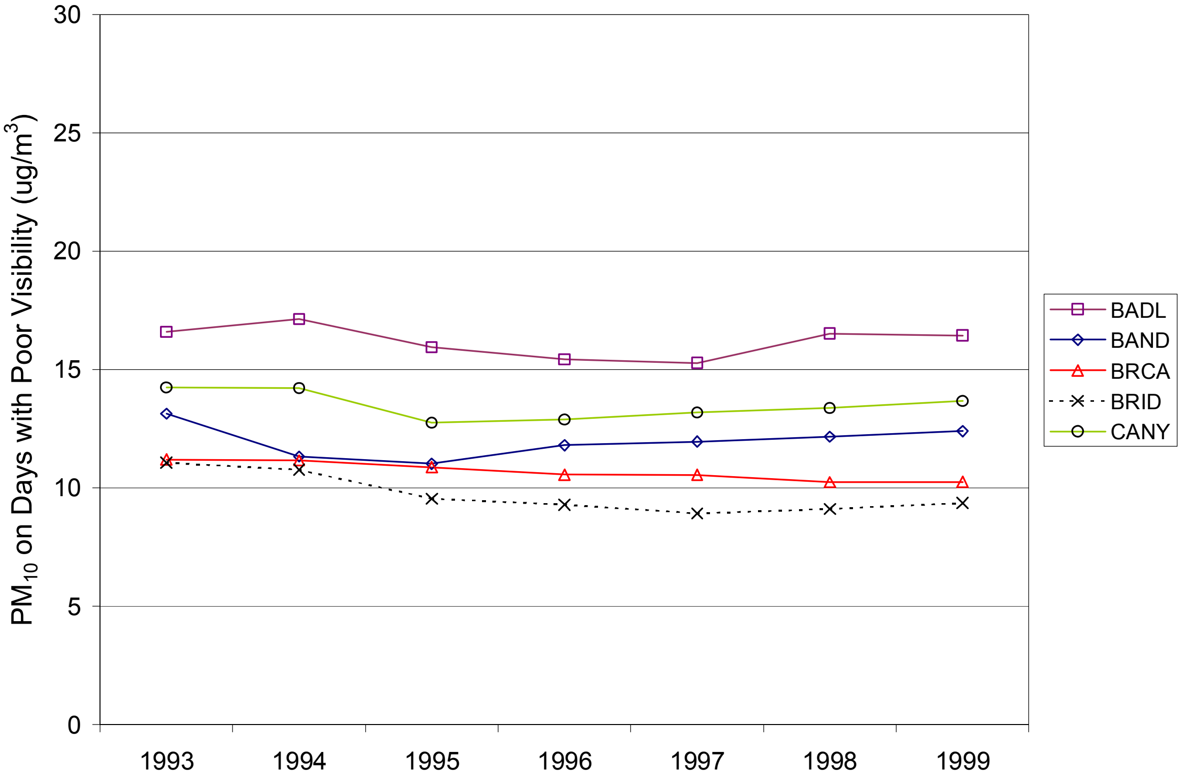



PM$_{10}$ on Days with Average Visibility (ug/m^3)
0
2
4
6
8
10
12
14
1993
1994
1995
1996
1997
1998
1999
CHIR
CRLA
DENA
GLAC
GRBA


PM$_{10}$ on Days with Average Visibility (ug/m^3)
0
2
4
6
8
10
12
14
1993
1994
1995
1996
1997
1998
1999
GRCA
GRSA
GUMO
JARB
LAVO

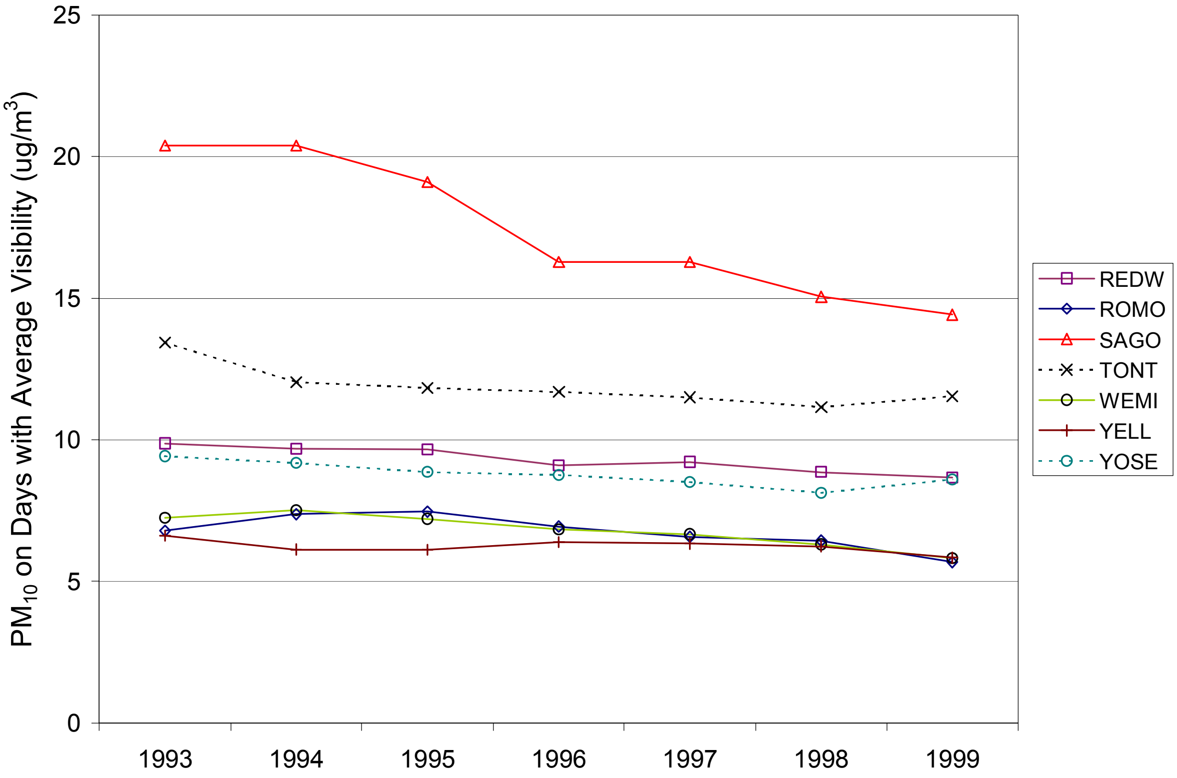


PM$_{10}$ on Days with Average Visibility (ug/m^3)
25
20
15
10
5
0
1993
1994
1995
1996
1997
1998
1999
MEVE
MORA
PEFO
PINN
PORE



PM$_{10}$ on Days with Poor Visibility (ug/m^3)
30
25
20
15
10
5
0
1993
1994
1995
1996
1997
1998
1999
BADL
BAND
BRCA
BRID
CANY

Figure III-11. Trends in PM_{10} Concentrations at Western IMPROVE Sites on Days with Poor Visibility (Worst 20 Percent).



SECTION IV:
A CONCEPTUAL MODEL OF REGIONAL HAZE IN THE WEST AND THE ROLE OF STAITIONARY SOURCE NOx AND PM EMISSIONS

Introduction

The objective of this report is to provide a foundation for better understanding the dynamics of PM in the West, with particular attention to the nitrate and primary component that may be due to point source emissions. Further, the report explores how stationary source NOx and primary PM controls might impact FPM levels. As part of that, the utilization of a trading system is discussed. The report sets up a detailed framework to understand the issues by developing a conceptual model of PM formation, atmospheric dynamics, and impacts in the West. Next, the report discusses the likely effectiveness of PM and NOx controls on PM levels in the West and the relationship with visibility. This section also deals with issues involving emission trading. The final two sections discuss potentially useful computer simulations and a summary.

Overview of PM in the West

The area covered by the Western Regional Air Partnership (WRAP) includes a large fraction of the continental United States. In an air quality management context, this area has very different air quality characteristics. In part, this is due to the diversity in the source characteristics of the region, ranging from large coastal California cities to very sparsely populated and isolated regions. In the former, the emissions are dominated by mobile sources, disperse human activities, and a variety of industries. In the latter, natural sources (e.g., fire, dust, and biogenic emissions) and large point sources (e.g., electricity generating units) can dominate. Similarly important are the meteorological and topographical differences: e.g., rainy and cool coastal areas in the Northwest, dry mountainous regions further inland, and deserts in the Southwest. Pollutant levels and characteristics vary accordingly. Not only do the relative levels of pollutants vary, but the composition and source contributions change as well. This is especially seen in the particulate matter composition. In Los Angeles, nitrate (and the associated ammonia) is a major contributor. Outside of California, nitrate is usually a relatively minor contributor, though the Columbia Gorge and Seattle areas find somewhat elevated levels (Malm et al., 2003).

Unlike gases, particulate matter is characterized not only by its composition, but by the particle size as well. From a regulatory standpoint, particulate matter is divided in to three fractions: fine, coarse and very coarse. To a degree, these capture how the particulate mater size distribution is considered from a scientific perspective, which is broken in to four modes of ascending size: nucleation, Aitken, accumulation and coarse modes. The nucleation mode is the very fine fraction where new particles are formed from nucleation of vapors. Recently, as part of the Supersite experiments, regional nucleation events have been seen. These particles then grow into the Aitken mode, which also contains primary emissions from combustion sources, and finally the accumulation mode. The accumulation mode is aptly named as the smaller particles grow in to this mode, but the growth out of accumulation mode particles into the coarse mode is very slow. Recent interest has grown over another possible division of PM: ultrafines (having particle diameters less than about 0.1 um). There is relatively less information about ultrafine PM.

Fine particulate matter (FPM) is often measured as PM2.5, or particulate matter with an aerodynamic diameter less than 2.5 micrometers (um). Some measurements of FPM have used other cut points, but there is a natural cut point at 2.5 um between the accumulation and coarse modes. On a mass basis, FPM is dominated by PM in the accumulation mode. Thus, coarse particulate matter is the fraction with particle diameters greater than 2.5 um. Given the historical measurements of PM10, coarse PM is often taken as the fraction between 2.5 and 10 um. The fraction above 10 um can be considered as very coarse, and is included (along with the other fractions) in total suspended particulate matter (TSP) measurements. The reasons for using these ranges have to do with the somewhat distinct dependence of the various size fractions on source, their atmospheric dynamics and impacts. Also, if one looks at a size distribution of PM, these modes become apparent. Characteristics of the coarse fraction are that the particles are mechanically generated (e.g. from road dust, construction, mining, etc.) and have relatively shorter atmospheric lifetimes due to settling and deposition, particularly for the very coarse particles. FPM can be mechanically generated (FPM can be present as the tail end portion of emissions that are mostly coarse) or from chemical conversion (SO2 oxidation to sulfate, combustion generation of soot, etc.), the latter often dominating. FPM also has a longer lifetime in the atmosphere as it deposits relatively slowly, though rain can rapidly remove much of the FPM. Ultrafines are due to emissions from combustion sources and chemical reactions in the atmosphere. Like FPM, ultrafines deposit slowly, but have a limited atmospheric lifetime as ultrafines because they grow due to condensation and coagulation.

While size differences are important, so are species differences. Sulfate is almost solely a secondary species, formed from the oxidation of SO2 (e.g., from coal-fired EGUs and other combustion processes). This may take place in the gas phase or from heterogeneous reactions. Sulfate is found in the fine fraction. Sulfate tends to be one of the largest components of FPM in the rural West, and still a major fraction in urban areas. Average levels are about 1 ug/m^3 in rural western areas. Nitrate is also a secondary component, resulting from the oxidation of NOx to form nitric acid gas, which then undergoes gas-to-particle conversion. NOx emissions are dominated by combustion sources, though there is a small fraction from biogenic emissions. Nitrate is also primarily in the FPM range, though tends to have a somewhat larger average particle diameter than the sulfate. A fraction of the nitrate is found in the coarse mode, indicative of gaseous nitric acid reacting with preexisting CPM (Malm et al., 2003). In the West, typical levels of measured nitrate outside of and not downwind of urban areas and central California tend to be low, averaging well less than 1 ug/m^3. In the Los Angeles basin, nitrate levels can exceed 25 ug/m^3, and significantly impact areas downwind. Care should be taken in interpreting measured nitrate levels as the techniques used are subject to artifacts (both positive and negative).

Organic carbon (OC) is the most complex part of the PM in many ways. First, it is comprised of many different species. Further, it can be primary or secondary, and biogenic and anthropogenic in origin. Again, OC is primarily FPM. Levels are highest in the cities or in areas with biomass burning (e.g., due to wild or planned fires), and there is growing evidence of the importance of secondary OC (Brown et al., 2000).

Elemental carbon (EC), or black carbon, is due to incomplete combustion, and appears to be primarily from wood burning and diesel vehicle emissions, though other sources contribute, and the actual fraction due to diesel vehicles is under study. Given the sources, EC is highest in urban areas, and a relatively small component of FPM in rural locations. While small on a mass basis, EC does absorb light, so can contribute more significantly to visibility degradation.

Metals, metal oxides and other crustal materials are due to a wide variety of sources, largely wind blown dust, as well as combustion, cement manufacture, etc. These are largely in the coarse mode, though a fraction is found as FPM, generally as the tail end of the size distribution of the coarse PM, or from combustion sources. In the non-coastal states of the West, the soil fraction is between about 20-30% of the FPM (Malm et al., 2003).

FPM has come to attention as an important fraction of the total particulate matter because of its potential impacts. FPM has been suspect of impacting human health, and recent and continuing studies tend to provide further support. (Less information is available for ultrafines). FPM also exists in a size range (e.g., similar to the wavelength of visible light) that effectively scatters and absorbs light, decreasing visibility, which is of particular concern in the West with its many national parks, forests and wilderness areas. Coarse particulate matter is of less concern (though still some) due to its shorter lifetimes, apparently reduced health effects and it is less effective, on a mass basis, of scattering light.

FPM levels in the West go from very low, with some of the lowest annual averages found in the US, to very high, with the Los Angeles area experiencing some of the highest. Other areas in the West experience isolated events of high PM (e.g., due to dust storms and fires) but annual average levels tend to be low. In much of the West and other parts of the country, the FPM is dominated by organic carbon and sulfate, while nitrate is typically a more minor constituent. While levels of these components, as well as FPM in general, are usually lower than in the east, the sources appear to be similar: sulfate comes from fuel combustion, particularly coal fired power plants and organic carbon comes from biomass burning and secondary formation. Of interest, recent results from the BRAVO study using molecular markers (Brown et al, 2002) suggest that a significant fraction of the organic FPM is secondary, as do similar studies in the Southeast. Carbon 14 dating of the organic matter in the Southeast (Edgerton, 2002) further suggest that the secondary organic is biogenic, which, given the emissions in the Big Bend area, would likely be the case there. Unlike most other areas, in Los Angeles and the Central Valley of California nitrate is a significant contributor, along with organic carbon and some sulfate.

Literature Review

Particulate matter dynamics has been an on-going research topic for decades. In-depth treatments of atmospheric particulate matter are contained in Seinfeld and Pandis (1998) and Friedlander (1977). The impact of PM on visibility has likewise been studied for years, with early work by van de Hulst (1957), and on-going study from the IMPROVE (Interagency Monitoring of Protected Visual Environments) program begun in 1985 (e.g., http://vista.cira.colostate.edu/improve/, and Malm, 2000, and references there in). Early studies of nitrate dynamics and response to emissions controls include Stelson and Seinfeld (1982) and Russell and Cass (1984).

In the WRAP area, particulate matter studies have been conducted for years. One could group them in to urban vs. pristine area studies, or a second split could be California studies and the rest of the west. The urban vs. pristine area consideration is typified by studies with different considerations, e.g., in urban areas health and attaining the National Ambient Air Quality Standards are often the drivers, while in pristine areas, visibility is of primary importance. The latter distinction, between California and other areas in the west, is made on a couple of bases. First, California has been very active in conducting air quality studies, in part because of the severe air quality problems in that state. Second, as presented in the regional conceptual model discussion below, particulate matter in regions in California is compositionally distinct from what is found over much of the West.

Outside of California, the primary information that is available concerning PM in the West is derived from the IMPROVE program (e.g., Malm, 2000), and a number of studies focusing on specific areas. IMPROVE is an ongoing study of visibility in Class I areas in the U.S. most notably national parks. Amongst its objectives are to monitor the composition of particulate matter in protected environments and identify sources. Other, more regionally focused studies include the Big Bend Regional Aerosol and Visibility Observational (BRAVO) study (see Green et al., 2000, Brown et al., 2002) those associated with the Grand Canyon and Colorado Plateau (e.g., Grand Canyon Visibility Transport Commission, 1996 and project MOHAVE: Lowenthal et al., 2000), Mt. Zirkel (e.g., Watson et al., 2001), the Denver Brown Cloud, which included the Northern Front Range Air Quality Study (NFRAQS) (e.g., Watson et al., 1998). The Grand Canyon studies were directed primarily at assessing how nearby power plants (in particular, the Navajo Generating station) impact visibility in areas on the Colorado Plateau, which includes a number of Class I areas, including the Grand Canyon, which had experienced days with decreased visibility. BRAVO is assessing the sources of particulate matter and visibility degradation in the Big Bend area of Texas, and NFRAQS studied visibility in the area around Denver. While not focused on PM in the West, the Southern Appalachians Mountains Initiative (SAMI) study (SAMI, 2002) is relevant here because it addressed many of the same issues, except for the focus on Class I areas in the southeastern United States.

Within California, a number of programs are available for providing information on particulate matter in various regions. First, a number of Class I areas in the state do have IMPROVE monitors, which provide both a long term record of PM composition, as well as a means of comparing, directly, levels in California with those in other states. In addition, California has conducted a number of additional, intensive efforts, most notably in the Los Angeles area and the Central Valley. In the Los Angeles (or South Coast) Basin, two studies are of particular note: the Southern California Air Quality Study (SCAQS) and the Southern California Ozone Study, 1997 (SCOS97). There have been a number of additional studies as well, notably those by Cass and coworkers (e.g., Hildemann et al., (1984); Gard et al., 1998), and the current studies associated with the Supersite (e.g., Sioutas et al., 2003). In the Central Valley, the San Jaoquin Valley/Atmospheric Utility Signature Prediction Experiment (SJV/AUSPEX), the California Regional Particulate Matter Air Quality Study (CRPAQS) and the Fresno Supersite are providing detailed information on the air quality and sources in that region. The two Supersite studies, however, are more focused on urban air quality, and less focused on visibility in protected areas.

A number of publications and reports discuss the results of the IMPROVE program, documenting the composition and trends and their relationship to visibility. A recent manuscript by Malm et al. (2003) presents the annual average fine particulate matter composition in each of 30 IMPROVE regions. In general, sulfate levels in the West are significantly below those in the East. Ammonium nitrate is high in southern California and the Lower Central Valley, with very low concentrations most other locations in the West (generally less than 0.5 ug/m^3 except in isolated spots, Malm et al, 2003). It should be noted that ammonium nitrate is actually not measured, but inferred from the nitrate measurements. As they note, nitrate can also be found in other forms, some of which are thermally stable (e.g., from the reaction of nitric acid with soil or sea salt, Malm et al., 1994; Gard et al., 1998). Organic carbon, regionally, typically runs between 0.5 and 2 ug/m^3. Elemental carbon levels are low, typically below 0.5 ug/m^3 on average, but can be an important component in terms of visibility reduction. A recent trends report from IMPROVE (Malm, 2000, also see Sisler et al., 2000 and Malm et al., 2002) shows that trends in PM levels are mixed throughout the West. For example, Sisler et al., (2000) found that of the western sites where a significant trend was found, not quite two thirds reported improvements. In some cases, decreases of one component (e.g., sulfate) were off set by another (e.g., organic carbon), as found at Jarbridge Wilderness area. At the Guadalupe Mountains NM, organics are going down, but nitrate and fine soil are going up, with no real change in visibility.

In the Mt. Zirkel Visibility Study (Watson et al., 2001), the major components that impaired visibility were found to be sulfate, organic carbon and crustal material, similar to the results form IMPROVE monitors in the region. Nitrate was a small contributor. Greater amounts of nitrate were found during the NFRAQS study, presumably because of the more concentrated sources of oxidized nitrogen in an urban area, and the proximity of confined animal operations.

Given the use of regional PM modeling, it is instructive to compare the modeling conducted here with similar studies, in particular BRAVO and SAMI, as well as other applications of PM regional models. In the SAMI study, the Urban-to-Regional, Multiscale (URM) model was used (Odman et al., 2002), and used the Decoupled, Direct Method (Yang et al., 1997) to assess source impacts and response to controls. They also assessed the response of PM levels to emissions changes corresponding to varying levels of controls. Results of their modeling was used to calculate the expected changes in visibility, stream health and ozone damage (SAMI, 2002). Model simulations led to FPM mass having an normalized error of under 50%. Sulfate and elemental and organic carbon simulations also found errors on the same order, but nitrate predictions were high. Seigneur (2003) recently completed a report discussing regional modeling applications of CMAQ and REMSAD, two of the more commonly used regional PM models. The focus of this review was the model performance in the BRAVO, WRAP, Southeast US and various EPA studies. In general, model performance in the studies outside of the WRAP found PM predictions with a normalized error of 35-90%. Nitrate predictions had the largest error.

SAMI air quality modeling dealt with many of the same issues being addressed currently by the WRAP (Odman et al., 2002). Specific issues addressed were quantifying the relationship between emissions and various air quality endpoints, including PM levels, deposition and ozone. PM results, which were by species, were used for visibility calculations. Specific results of relevance here include:

- PM reductions were sub-linear to controls, and that the degree of sub-linearity increased as PM concentrations decreased. For example, when sulfate concentrations were highest, a 10% reduction in SO2 emissions resulted in an approximately 8-9% reduction in sulfate. At lower sulfate levels, the same 10% reduction led to a smaller percentage change. For nitrate, the sub-linear response was greater. A 10% reduction in NOx led to about a 5% reduction in nitrate, averaged over the year.

- Reductions in sulfate led to an increase in nitrate levels.

- Increases in ammonia led to an increase in nitrate.

- Nitrate formation was generally ammonia-limited.

These findings are important both individually and collectively. Over the next few years, SO2 emissions are expected to decrease and ammonia emissions are expected to increase, both leading to increases in nitrate. SAMI results suggest that these increases will be relatively small, but non-zero. However, in many locations, they offset the 27-63% reductions in NOx, such that nitrate actually increased. It is difficult to translate how similar changes will impact the WRAP regions, particularly since the WRAP regions are more heterogeneous. However, the preliminary results from the CMAQ modeling suggest that nitrate formation is ammonia-limited in a large part of the West. The sub-linear response suggests that controls will not get as much reduction as might originally be expected. However, the greatest fractional improvements will occur on the most heavily impacted days.

A final reference that provides a good overview of the issue is the NARSTO Assessment (NARSTO, 2003). It provides a more thorough discussion of many of the issues contained here, as well as conceptual models of PM dynamics in a number of areas of the United States.

Conceptual Model of Primary PM and Nitrate Dynamics in Western Airsheds

Here, conceptual models are developed to help elucidate the dynamics of both primary and nitrate PM in various western airsheds, starting with primary coarse and fine PM, which are not as involved with gas-to-particle conversion and less complicated. Note, secondary species can condense on primary PM, so even primary species can impact the formation and properties of secondary material.

Coarse PM is typically emitted by mechanical processes, e.g., grinding operations, transport of solid materials, road dust and wind blown dust. Further, CPM is typically emitted near the ground, not from tall stacks. In part, this is due to controls on large point sources. CPM has a relatively short lifetime, on the order of a few hours, though particles at the upper end of the coarse mode will have very short lifetime. For wind blown dust, this is much of the mass. Primary CPM can be attacked by nitric acid, and because of the shorter lifetime, act as a sink of nitrate PM. Given total primary CPM emissions of 70 tons per year (tpy) (1/2 of the total PM10 emissions), one can develop a first order estimate of the contribution to total PM in the region by dividing by the approximate volume of the boundary layer in the WRAP area (~10^{15} m^3), and multiply (~1 hr) by the lifetime. This leads to an average contribution of large point sources to PM of 0.005 ug/m^3, a small fraction, again, on average. However, high levels of CPM are often very episodic (dust storms) or very local: i.e., within a few km of the source. Further downwind, the emissions have deposited and been diluted.

A portion of the CPM can be secondary, e.g., due to reaction of nitric acid on the surface of the aerosol, or condensation. Measurements suggest that a non-insignificant fraction of the nitrate in the regions outside of the California valleys is coarse. As discussed below, the existence of CPM nitrate is important from a control point of view. CPM nitrate is less likely to be reduced from reductions in ammonia as compared to FPM nitrate.

From this conceptual model of CPM, driving points are:

- CPM is predominantly primary, with a fraction due to gas-to-particle conversion, e.g., by the reaction of nitric acid with pre-existing particles,
- CPM has a relatively short lifetime,
- CPM can act as a sink for nitrate, and
- CPM is typically episodic, often occurring during periods with large amounts of windblown dust.

Primary FPM is emitted, often as a combustion by-product, in to the atmosphere, where it undergoes transport, growth, deposition, rain-out and a variety of other processes. The size of such emissions are typically in the ultrafine region, though from some processes the average particle size can be larger, e.g., as fine and coarse PM (e.g., cement manufacture). If emitted as an ultrafine, the small particles will likely grow in to the accumulation mode via condensation of other compounds to it (primarily) and coagulation with other particles, staying as FPM.

Primary FPM is transported very efficiently, essentially as a gas, since its sedimentation velocity (the rate at which it falls due to gravity) is very slow. As such, it will follow the prevailing winds and be distributed vertically and horizontally due to atmospheric turbulence. Removal of FPM occurs due to wash-out (e.g., rain and snow) and dry deposition. Dry deposition is slow, slower than many gases, due to the slow transport of FPM across the fluid dynamic boundary layer near solid surfaces (gases diffuse much more rapidly than particles) and low sedimentation velocities. As an example, for a 1 um particle, the deposition velocity is on the order of $5x10^{-4}$ m s^{-1}. Using a boundary layer height (e.g., the well mixed portion of the atmosphere near the earth's surface) of 1000m, this leads to an atmospheric lifetime of about 3 weeks, and the particles will be transported out of the region before depositing. Larger particles will deposit somewhat faster as their sedimentation velocity is higher (the particles are heavier), and very small particles will as well since they diffuse faster. With such long lifetimes, wash-out can be very important, particularly in areas that have frequent rains. Depending on the intensity of the rain, FPM can be very effectively removed, such that the lifetime of the FPM is very directly linked to the frequency of rain. Without rain, FPM is generally transported out of the airshed or, as will be discussed for nitrate, be lost due to some other process. The lifetime due to transport in the region is on the order of 10 days. Using this, along with assuming that one half of the primary PM emissions from stationary sources (Seignuer et al., 2003) are fine, one calculates that the average primary FPM levels would be on the order of 1 ug/m^3. This is somewhat above what is measured as crustals in most locations, and more in line with the measured organic carbon. However, organic carbon would be due more to wood boilers and internal combustion engines. Using just those emissions, the average contribution to the organics would be less than 0.1 ug/m^3. This is in line with source apportionments that suggest a large fraction of the organic carbon is due to biomass burning and other processes (e.g. Maykut et al., 2003). The stationary source emissions estimates would suggest that primary FPM from stationary sources may have a regionally significant impact, though this calculation is conservative and does not take in to account rainout and other loss processes.

If the primary FPM is emitted from the stack of a large point source, it will be transported in the plume with the gaseous pollutants and can undergo somewhat more rapid growth due to the concentration of condensable compounds. It may also be transported above the well mixed boundary layer, delaying the dry deposition loss mechanism, at least temporarily. When the mixed layer grows to capture the plume, the FPM will be diffused downwards. Given the cloud heights relative to the typical effective plume height, washout will typically remove FPM from plumes.

During transport, primary FPM can grow. Growth will depend upon the particle size and composition. Of particular importance is the hygroscopicity of the compounds in the particles. Some compounds will readily absorb water, such that in a humid environment, they will grow significantly, e.g., doubling in size. If the compound is hydrophobic, they will undergo more slow growth due to condensation of other compounds. Water is not the only compound that will be selective as to which particles are most readily absorbed. Semi-volatile organic gases can have a preference for particles with similar-structured organic matter already present. $SO_2(g)$ can be absorbed in to particles that already contain water, and then oxidized to form sulfate. Nitric acid will prefer non-acidic particulate matter. Important here is to recognize that a primary particle will interact with its environment, and end up as having both primary and secondary components. From a visibility standpoint, this is important since the growth can make the particles more efficient at degrading visibility. While the argument could be made that the condensable species would find some other process to form particulate matter without direct emissions (e.g., nucleation, followed by condensation), there is an abundance of water that would not necessarily do so. Further, as compounds such as sulfate condense on primary FPM, they can become more hygroscopic. Since primary emissions of FPM can undergo atmospheric growth, it is not directly apparent that decreases in FPM emissions will lead to the same level of decrease in FPM in the atmosphere. Indeed, greater reductions may be realized if the nuclei provided by the primary FPM is a limiting factor in the formation of secondary FPM. On the other hand, the observed effects may not be as enhanced since the condensable species will find other particles.

From this conceptual model of primary FPM, driving points are:

- FPM has potentially long lifetimes in the atmosphere,
- Wash-out is an important loss mechanism,
- Ultrafine primary FPM can grow in to a size range that is efficient at scattering light,
- Hygroscopic FPM can pick up water and become diffusive, and
- Even if emitted from tall stacks, primary FPM can be diffused downwards to the surface.

Particulate nitrate dynamics is significantly more complex than for primary PM because of the added chemistry and gas-to-particle/particle-to-gas conversion. While there is a small amount of primary nitrate emissions, most of the particulate nitrate in the troposphere starts out as NO_x which was emitted from a combustion process. NO_x, which is well known for its role in the formation of ozone, can be oxidized to nitric acid via two important pathways. During the day, NO_2 is oxidized by the hydroxyl radical:

$$NO_2 + OH \longrightarrow HNO_3$$

This reaction is responsible for most of the nitric acid formation. A second route takes place mostly at night. First, NO_2 is oxidized by ozone to the nitrate radical, NO_3:

$$\mathrm{NO_2 + O_3 \longrightarrow NO_3 + O_2}$$

(The nitrate radical should not be confused with the nitrate ion, NO_3^-). Next, the nitrate radical reacts with NO_2 to form dinitrogen pentoxide, N_2O_5:

$$\mathrm{NO_2 + NO_3 \longrightarrow N_2O_5}$$

N_2O_5 then reacts with water to form two nitric acid molecules:

$$N_2O_5 + H_2O \longrightarrow 2HNO_3$$

This reaction is slow in the gas phase, but can occur rapidly on the surface of a particle that contains water. However, the rate of this reaction is very uncertain, and it is believed that the rate used by CMAQ in the past may be too high (Dennis, 2003, personal communication), leading to an over prediction of PM nitrate. NO_3 photolyzes very rapidly, and during the daytime it is found at very, very low levels, blocking this formation route when the sun is up.

The nitric acid gas formed from the above reactions can dry-deposit out, be washed out, or undergo gas-to-particle conversion. Nitric acid reacts very rapidly with surfaces, and deposits out rapidly. It's lifetime to dry deposition is on the order of a few hours. Nitric acid is also very soluble, and is removed effectively by rain.

In terms of particulate matter formation, nitric acid is a strong gas and can attack pre-existing particles, being adsorbed or displacing other compounds present. For example, nitric acid gas can displace chlorine in a sea salt-derived particle, leading to sodium nitrate and HCl(g). Likewise, it can react with alikilinic crustal material to form PM nitrate (e.g., Malm et al., 2003). In both such cases, the particulate nitrate formed is in the coarse fraction because the original particle was in the coarse mode. In many regions, the route to forming FPM nitrate is via the gas phase reaction between nitric acid and ammonia (NH_3):

$$HNO_3(g) + NH_3(g) \longrightarrow NH_4NO_3(\text{aerosol})$$

followed by gas to particle conversion. The reaction is reversible, and the ammonium nitrate can thermally decompose. The forward and backward reactions are fast enough such that the two reactions are often considered to be in equilibrium:

$$HNO_3(g) + NH_3(g) \xleftrightarrow{K} NH_4NO_3(\text{aerosol})$$

where K is the equilibrium constant. Thus, the fraction of nitrate formed is very sensitive to the abundance of ammonia available, as probed later. In areas with substantial quantities of ammonia, large amounts of nitrate can be formed (e.g., in areas with confined animal operations). In areas with relatively little ammonia, or where the ammonia available is bound as ammonium sulfate (or ammonium bisulfate), very little nitrate is present. Another factor is that the equilibrium constant is very temperature dependent, and at higher temperatures, the gas phases of the two compounds is preferred. The equilibrium makes the formation of ammonium nitrate very nonlinear. In some cases, e.g., in an environment rich in ammonia but with little nitric acid, the ammonium nitrate levels are governed almost solely by the available nitrate (e.g., nitric acid formation), and ammonia reductions will have little impact. If ammonia is low, it is the controlling species

Surprisingly, nitrate levels, locally, may go up when NOx emissions are decreased. This is analogous to the disbenefit found in the response of ozone to NOx emissions. Regionally, NO_x reductions will reduce ozone because NO2 is needed to form ozone. However, locally, reducing NO_x can lead to local increases in ozone for two reasons. The most easily understood is that NO_x is primarily emitted as NO, which titrates ozone. This is important at night. During the day, NO_2 reacts with the hydroxyl radical, significantly lowering OH levels. This decreases the rate of VOC oxidation, which reduces the rate of NO oxidation to NO_2, which reduces ozone formation. Most of the hydroxyl radical formed comes from ozone photolysis, so lower ozone reduces OH formation. Thus, there is a positive feedback. NO_x emissions increases decrease ozone, decrease OH, and decrease the rate at which NO_2 is oxidized to nitrate, locally. Regionally, more nitric acid will be formed. In the SAMI study, this appeared to be a second order effect.

Complicating the nitrate formation issue is the presence of other condensed phase species, in particular sulfate. As noted above, ammonium nitrate formation is very sensitive to the availability of ammonia. SO_2 oxidation, which is faster in the summer when hydroxyl levels are highest, leads to the formation of sulfuric acid, H_2SO_4. Sulfuric acid reacts with ammonia to form ammonium bisulfate [$(NH_4)HSO_4$], and if enough ammonia is present, ammonium sulfate

[$(NH_4)_2SO_4$]. Ammonia will preferentially react with sulfate to form the above two species before reacting with nitric acid to form ammonium nitrate. As such, the presence of sulfate will reduce the amount of ammonia available to form ammonium nitrate. In many cases, there is so little free ammonia that ammonium nitrate is not formed. On the other hand, nitric acid that has reacted with sea salt or crustal material to form sodium/calcium nitrate does not require ammonia, so there can be some aerosol nitrate even in high sulfate areas, though typically not as much as in high ammonia/low sulfate areas.

The interaction between sulfate, nitric acid and ammonia has implications for the "lifetime" of nitrate in the atmosphere as sulfate is reduced: decreasing sulfate will make more ammonia available to form PM nitrate, reducing nitric acid gas levels. The PM nitrate deposits much less rapidly than nitric acid, so the total abundance of nitrate in the atmosphere will increase. Thus, decreasing sulfate levels may lead to somewhat more nitrate than is expected from just considering the amount of nitric acid currently available to form PM nitrate.

Sulfur dioxide reductions will lead to the reduction of sulfate particulate matter, and hence, can lead to more ammonium being available to form ammonium nitrate, leading to what is referred to as the "rebound effect". In this case, the sulfur dioxide controls will not lead to the expected (or desired) reductions in particulate matter because as sulfate decreases, nitrate increases due to the availability of ammonia in a condition where nitrate formation was ammonia limited. This was found to be true in the SAMI study to a limited degree.

One issue that should be addressed is the impact of certain NOx controls on increasing ammonia emissions, e.g., SCR and SNCR. Compared to other sources of emissions, such controls would represent a very small fraction of the total ammonia emissions. However, in the plume, the ammonia emissions might be high enough to lead to an increase in ammonium nitrate, and hence impact visibility in concentrated plumes.

Washout is very important to nitrate levels. Not only will rain remove the nitrate aerosol, but will also remove nitric acid gas and ammonia very effectively. Clouds can also increase the oxidation of SO2 to sulfate, which captures ammonia, and is also washed out. Some of the lowest FPM levels are found following a rain storm.

From this conceptual model of PM nitrate, driving points are:

- PM nitrate formation is due to both gas and heterogeneous reactions forming nitric acid from nitrogen oxide emissions, followed by gas-to-particle conversion,

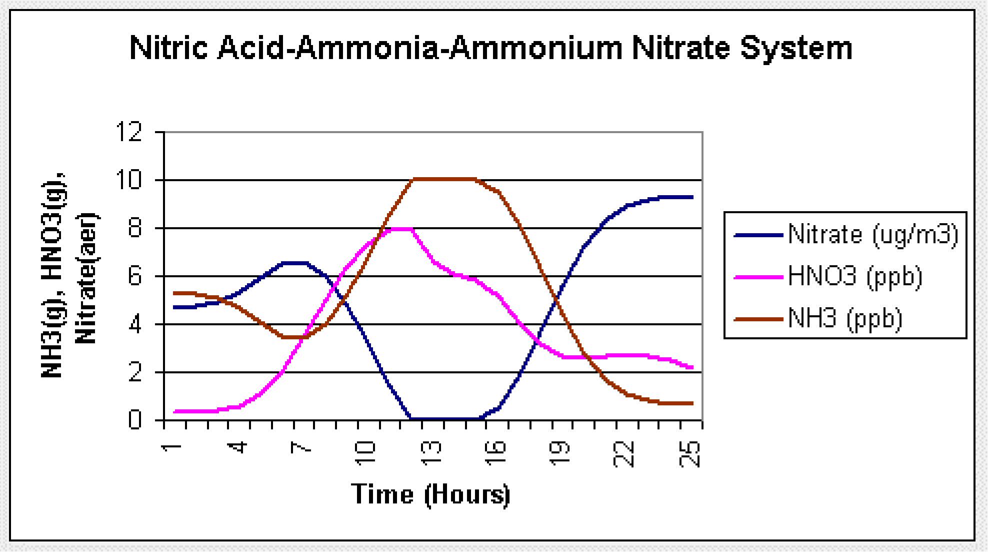
- FPM nitrate is largely due to reaction with ammonia, while CPM nitrate is due to reactions of nitric acid on a preexisting particle,

- Reducing ammonia can reduce nitrate formation in areas that are "ammonia limited", but may have little impact in areas where there is an abundance of ammonia, and

- NOx controls can reduce nitrate in areas where ammonium nitrate formation is nitrate limited, as well as areas where nitrate is formed from the reaction of nitric acid on pre-existing particles.

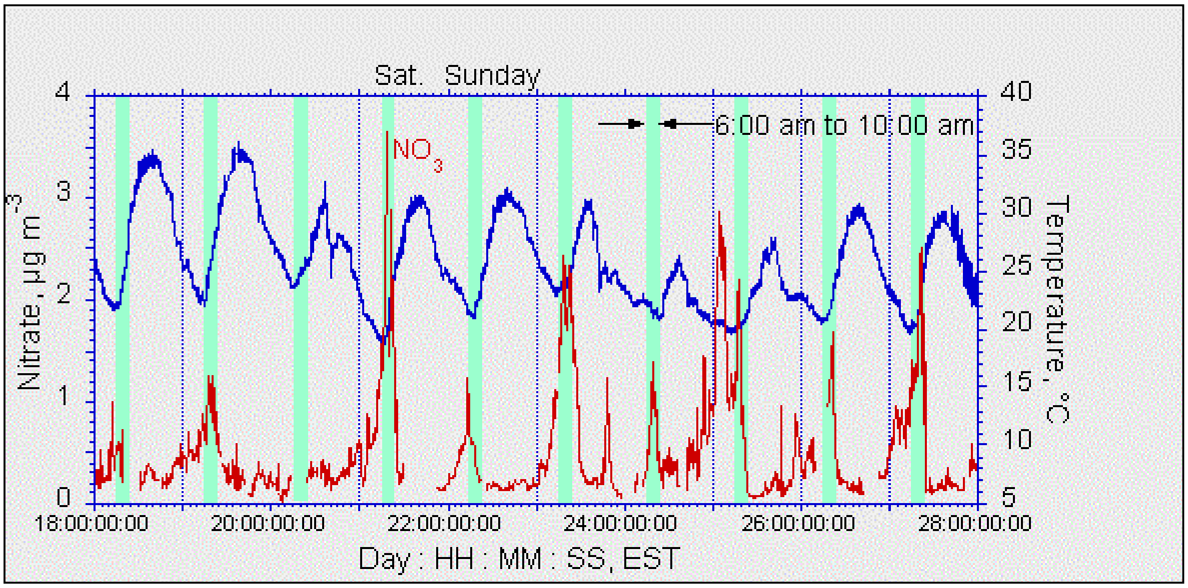
This conceptual model is diagrammed in the figure below. It should be noted that this figure, or the discussion above, does not have all of the complexities leading to nitrate formation. The atmospheric chemistry involves hundreds of compounds, and thousands of reactions. Describing the physical processes is equally complex. The systems of equations governing the pollutant evolution are non-linear. Pollutants evolve spatially and temporally. For such reasons, complex computer models are generally used to study the details of the pollutant dynamics. However, a good picture of the system dynamics, and an understanding of the importance of various processes can be developed from a simplified, zero-dimensional model.

While very simplified, a zero-dimensional model can be used to demonstrate the important features and resulting formation and loss of particulate nitrate. In this case, the model includes the formation of nitric acid, peaking during the day, an increase in temperature during the day, going from 10 to 30 C, the increase in the equilibrium constant with temperature, deposition of nitric acid, and a constant level of ammonia/ammonium. The result is that the highest levels of PM nitrate occur at night and the early morning, going to zero during the hottest parts of the day. Nitric acid peaks during the day when all of the ammonium nitrate has dissociated. Most of the nitrate deposits during the day since nitric acid is so reactive with surfaces. In the SAMI project, the deposition of oxidized nitrogen due to nitric acid was about an order of magnitude higher than for PM nitrate, due both to the higher nitric acid levels and deposition velocities.



One of the important features of this system is that while ammonium nitrate does not deposit rapidly, nitric acid does. Thus, an ammonium nitrate aerosol will disappear relatively rapidly in a continual, two-step process: the nitric acid gas deposits rapidly as a gas. The ammonium nitrate will thermally decompose to replace the lost nitric acid. The nitric acid released will then deposit out, etc.. At higher temperatures, i.e., when a significant amount of the nitrate is in the gas phase, this process can be rapid. In cold areas, almost all of the nitrate will be bound as ammonium nitrate, and the thermal decomposition is slow, so the process is inhibited.

A multi-day observation of aerosol nitrate levels is shown in Figure 2, along with the temperature trace. As shown, nitrate goes up in the morning due to NOx oxidation along with low temperatures. As the temperature increases, the nitrate decreases and goes to near zero during the day. While not shown, sulfate also increases during the day, scavenging ammonia and further decreasing nitrate levels.



Particles and Visibility

As noted previously, particles can degrade visibility. The three primary mechanisms are Mie, Rayleigh and Geometric scattering, and absorption. Only a few types of particles absorb visible light effectively. Most notably is elemental carbon. Mie scattering occurs from a complex interaction between light waves and particles of a size similar to the wavelength of light (visible light ranges from about 0.2 to 0.8 um). Larger particles scatter and block light. Air molecules also scatter light (Rayleigh scattering), limiting visibility on even the cleanest days.

Visibility, or visual range, x_v, is often calculated using the Koschmeider formula:

$$x_v = \frac{3.912}{b_{ext}}$$

where b_{ext} is called the extinction coefficient, and is generally given in Mm^{-1}. The extinction coefficient is calculated by accounting for all of the processes scattering and absorbing light. While very complex formulas have been derived, a useful parameterization that corresponds to he air quality data usually available from IMPROVE and other sites is:

$$b_{ext} = 3 f_T(RH)([Sulfate] + [Nitrate]) + 4 f_{org}(RH)[Organic] + [Soil] + 0.6[CPM] + 10[LAC]$$

where $f_T(RH)$ is a function to account for sulfate and nitrate absorbing water ($f_{org}(RH)$ is a similar function for organic material), [Sulfate], [Nitrate], [Organic] and [Soil], are the measured masses of the corresponding fine PM constituents, and [LAC] is the measured mass of the "light absorbing carbon" similar to EC, (depending on measurement technique). The latter term accounts for absorption. At relative humidities (RH) above 40%, $f_T(RH)$ is greater than one, going up to above 5. However, $f_{org}(RH)$ is taken as one. Given this, one sees that, on a mass basis, sulfate and nitrate are usually more effective at scattering light than organics, soil and CPM. LAC is very effective at absorbing light, and a small amount can lead to significant light extinction. Another measure of visibility impairment is the deciview (Pitchford and Malm, 1993). It is proportional to the log of the extinction coefficient and relates to the perception of haziness. Given the non-linear nature of the relationship between deciviews and extinction coefficient, but the linear relationship between extinction and PM composition, for the purposes of this report, it is easier to consider extinction.

Regional Conceptual Models

The above description of the formation and fate of primary FPM and nitrate was done for a general case, without consideration of regional differences in either the processes impacting primary FPM and nitrate. In the West, many such regions exist. To provide a better understanding of how such differences manifest themselves, four sub-regions of the WRAP are identified based on their meteorological and FPM characteristics. The four regions are: wet coastal, dry mountainous, southwest desert, and California valleys. Wet coastal regions include the coastal regions starting in northern California to the Olympic Peninsula, and include the coastal mountains. The dry mountainous sub-region includes the Rockies, the Sierras, and other drier mountainous areas. The southwest desert region would include non-mountainous areas in Arizona, New Mexico, Colorado and Nevada. California valleys include the Los Angeles basin and the surroundings (including the mountainous and desert areas downwind) and the Central Valley and surrounding mountains. A fifth case, considered separately, but not as a separate region, "in-and-near,"., i.e., those regions that have significant sources of PM either directly within or nearby. For example, a Class I area near a major city or facility with very large emissions, or if the activities within a Class I area led to significant emissions. The IMPROVE investigators have dissected the west in to 15 regions, which is more than is needed for developing the conceptual models as done below. However, which "IMPROVE" regions fall in to each of the four given below are noted.

Wet, Coastal Subregion

This subregion occurs along the Pacific coast and the Puget Sound, in to the coastal mountains and the Cascades. As such, it includes the IMPROVE Pacific Coastal and Cascade Mountains. As the name implies, this region tends to be wet, and is known for rain, and can also experience intense coastal storms. The temperatures tend to be cool. There are a few population centers in this region (e.g., Portland and Seattle).

PM levels in the coastal region tend to be low, e.g., on the order of a 3-4 ug/m^3 average over the year (Malm et al., 2003). Average levels of nitrate and primary FPM are very low: 0.2-0.8 ug/m^3, though nitrate is higher in the Puget Sound and Columbia Gorge areas (Malm et al., 2003). The rain removes FPM and its precursors and coastal winds ventilate the region. The cloudiness of the area inhibits the rate of oxidation of NO2 to nitric acid. There are relatively fewer sources of FPM and precursors in the region. Higher levels of FPM are experienced in the population centers. In the Class I areas, FPM tends to be primarily sulfate and OC, with little nitrate and primary material. Biomass burning (e.g., forest fires) appears to be a major contributor in some areas, as suggested by high OC levels, particularly during some very high events. In terms of the general conceptual model, discussed above, particulate nitrate can be formed from the reaction of nitric acid with sea salt. Ammonium nitrate formation in the area appears to be limited by the presence of both free nitrate and ammonium. On the other hand, the cool temperatures promote converting what little available nitric acid and ammonia is available in to ammonium nitrate. Without further investigation (e.g., longer term, detailed modeling) it is difficult to tell how nitrate will respond to controls, but it is likely that the formation is limited by NOx emissions, not ammonia. Results from the WRAP modeling suggest that part of Oregon is ammonia sensitive (Tonneson, 2003).

The days with the most severe visibility impairment appear to be impacted most heavily by organics (particularly during severe episodes) and sulfate.

Dry, Mountainous Subregion

This region includes the more inland mountains, and would contain the Sierra Nevada, Wasatch, Northern Rocky, Sierra-Humboldt and Central Rocky Mountain IMPROVE regions. These areas are much drier than the coastal mountains. While not immune to rain and storms, they are less frequent, particularly during the summer. Temperatures tend to get hotter during the summer. During the winter, temperatures can get quite low. The area has a relatively low population density, and few major source regions, though is relatively agricultural. Major point sources include utility boilers, and smelting operations. Confined animal operations can lead to areas of very high ammonia. Forest fires, particularly in the northern mountainous areas (e.g., Montana and Idaho) and the Sierras can lead to very large PM concentrations during episodes. In such cases, OC dominates mass.

FPM levels in this region are low, around 2-5 ug/m^3 in Class I areas. Again, cities have higher levels. Nitrate and primary FPM levels are a small fraction of the total (0.1 to 0.4 ug/m^3, except in the regions of the Sierra Nevada that are influenced by emissions in the Central Valley), particularly during the some of the most polluted events that are dominated by sulfate. Given the low levels of nitrate, and the likely higher ammonia emissions, nitrate formation is likely limited by nitric acid formation from NO_2. Simulations by UCR tend to suggest a mixture of sensitivities (Tonneson, 2003).

The days with the most severe visibility impairment appear to be impacted most heavily by organic matter or sulfate, though some events have very high levels of coarse mass as well. Nitrate tends to be a relatively small contributor, which is to be expected when sulfate is high. Because the measurements can not distinguish as to the source of primary PM, it is not immediately apparent as to the source of the coarse mass, but given the episodic nature, it is likely that the primary PM is natural in origin.

Southwest

This region includes the far eastern part of southern California, Arizona, New Mexico, southern Colorado and Nevada. IMPROVE regions corresponding to this region are the Great Basin of Nevada, the Colorado Plateau and Sonoran Desert. The Southwest has features similar to the Dry Mountainous subregion, being dry and having low FPM levels. It differs in that temperatures tend to be higher, and there is a greater abundance of major point sources of NOx and FPM. Biogenic sources in much of the southwest are very small, but appear to be a major component of the OC nonetheless (Brown et al., 2000). Ammonia emissions are less dense, though crustal material can be higher from wind blow dust as this area finds higher soil concentrations than the others (Malm et al., 2003).. While more detailed modeling is needed, it would appear that the higher levels of sulfate measured, and the apparently lower levels of ammonia emissions, would make this area ammonia limited much of the time.

The days with the most severe visibility impairment appear to be impacted most heavily by sulfate, OC and nitrate, though some of the events with the lowest visibility have very high levels of coarse mass, likely associated with dust storms. There are periods with very high levels of OC, indicative of major biomass burning events (forest fires).

California Valleys

This subregion is the most distinct of the four, and includes California's Los Angeles Basin and the Central Valley, and the areas most directly impacted by transport from these regions (e.g., downwind of Los Angeles and the mountains directly along the valley, including part of the Sierra Nevada). This region is relatively dry and warm. There are periods of significant stagnation. Most importantly, this region has greater emission densities of the pollutants impacting nitrate PM, in particular both NOx and ammonia. These characteristics lead to substantially higher FPM levels, especially for nitrate. Nationally, this region has the highest nitrate levels.

Of all the regions, most is known about the dynamics of PM here due to a history of studies being sponsored by the state of California, industries and others. In Los Angeles, the high nitrate levels are due to the large emissions of NOx, e.g., from mobile sources, confined animal operations leading to high ammonia emissions, low ventilation rates concentrating both sets of emissions, and plentiful sun, oxidizing the NO2. In parts of the basin, e.g., before the air masses pass over the confined animal operations, nitrate formation is ammonia limited. Further downwind, the formation becomes nitrate-limited as there are plentiful ammonia emissions and the nitric acid continues to deposit out. The highest nitrate levels are found in the fall when the sunlight still leads to rapid oxidation of NO2, winds are light, there is little rain, and the temperatures are lower favoring the formation of ammonium nitrate. On hot summer days, the ammonium nitrate thermally decomposes, though large amounts of nitrate can be present during the cooler hours.

The Central valley shares some of the characteristics of the LA basin, but has some unique features. First, the sources of NOx differ, having a larger non-mobile component, and being less dense. There are widespread agricultural and animal operations leading to ammonia emissions throughout the valley. There can be long stagnation events with fog and very little ventilation. During these stagnation events, nitrate levels can build.

An interesting study of the NOx-nitrate relationship was recently completed for the San Joaquin Valley using a box model (Stockwell et al., 2000). They found that for each gram of NOx emission, approximately 0.6 grams of nitrate is formed. This is a high ammonia region, so while those results are in general agreement with field measurements in the region, the extrapolation of those results elsewhere is limited.

For both areas, the days with the greatest visibility impairment are high in nitrate, OC and sulfate, with episodes of coarse material.

In and Near

A few Class I areas lie very near a major source region (e.g., a city) or specific source (e.g., a major highway, mining operation or power plant). In this case, the PM levels can be higher than experienced by the rest of the region, and have a different composition. Examples that are near source regions include San Gorgonio (downwind of Los Angeles) and Casa Grande and Tonto National Monuments near Phoenix. In this case, the PM takes on a characteristic that is a blend between these in the urban area and the regional background. For example, this can lead to elevated nitrate, as particularly found in San Gorgonio, and organic and elemental carbon. For areas near major sources, the PM can be enriched in the compounds being directly emitted by the source. Secondary pollutants, particularly sulfate, take longer to form, so there is less of a direct impact, but some enrichment is likely (e.g. Grand Canyon Visibility Transport Commission, 1996; Pitchford et al., 1999). Pollutant dispersion reduces the apparent source impact relatively rapidly, so after a few 10s of km, the impact from that source is reduced by an order of magnitude or so. This is particularly true for CPM which also deposits rapidly. Also, human activities within a protected area (e.g., driving, fires, etc.) can contribute to locally higher PM levels. However, these sources are outside of the subject of this study, do not appear to be a significant contributor to visibility degradation regionally, and are not dealt with further here.

Particulate Matter Modeling

Currently, the most scientifically well-founded approach to assessing how future emissions changes will impact air quality is to use a physically and chemically comprehensive air quality model that describes the evolution of pollutants in the atmosphere. Such models (actually, multiple models are used) are complex, and are run on fast computers. The WRAP is now using such an approach. In particular, the WRAP is using the Models-3 suite of models, including SMOKE for emissions, MM5 for meteorology and CMAQ for air quality, including particulate matter. MM5 is one of the most widely used meteorological models, and CMAQ is an increasingly popular air quality model.

MM5 solves the equations governing the motions of the atmosphere. These equations are very complex and non-linear, and sensitive to boundary and initial conditions. The model uses a variety of parameterizations to simulate various processes. For some processes, MM5 has more than one choice of parameterization since no one approach appears to be universally best. This, in part, shows the complexity of meteorological models, and that modeling errors can be expected. Errors can grow with time, degrading performance in longer simulations if nothing is done to constrain the growth. For this reason, data assimilation is used where observations are used to adjust the results as the fields evolve. As such, the model results are sensitive to model inputs (including initial and boundary conditions), model parameterizations and errors in the data used in the assimilation. While MM5 often achieves very good performance, there are events where good performance is elusive.

CMAQ is a comprehensive chemical transport model, developed primarily by the US EPA and funding from that agency. It represents the state-of-the-science in most aspects, and has been developed for use by the modeling community. Its use by the community is, in part, to help it evolve and continuously improve. CMAQ contains processes describing gas phase chemistry, aerosol dynamics, dry and wet deposition, pollutant transport and more. A common configuration of CMAQ uses CB-IV, a rather older, simplified chemical mechanism, though versions exist with RADM-II and SAPRC-99, two of the newer, most comprehensive and well tested mechanisms.

All three models have been used in a variety of efforts in the past. MM5 and CMAQ, the two predictive models, have been able to show good performance, at least for some species, though performance can vary from site to site and study to study. Since CMAQ uses the results from MM5, poor performance by MM5 can lead to similarly poor performance from CMAQ. However, even with ostensibly good performance from MM5, CMAQ may not perform well due to poor emissions inputs and/or problems with CMAQ itself, e.g., how it treats various processes. Further, here, CMAQ is being applied using a 36 km grid resolution. Such large grids are not appropriate for assessing the impact of a point source of CPM on nearby areas because of the rapid deposition of the larger particles, and the artificially large dilution of the emissions over the 36x36 km grid.

Model Performance Issues

Confidence in using such a model is derived from successful evaluation of the results. What constitutes good model performance varies by pollutants, and for FPM there is no standard criteria. Recent modeling efforts have found errors for sulfate to be within about 50%, OC within a similar range, and nitrate within about 100% (Seignuer, 2003).
However, current model performance found for the WRAP effort suggests poor model performance for some species, particularly nitrate (up to a factor of 10 high in the winter, but some days with essentially no nitrate formation simulated in regions where nitrate is monitored to be present). It is difficult to assess the model performance for primary FPM from stationary sources since the measurements and the model results are not able to support such an evaluation. How does poor model performance affect the use of the results, in particular for quantifying the likely impact of emissions changes?

First, it is important to understand the likely reasons for the poor nitrate performance. It is unlikely that the NOx emissions estimates are very far off, so other problems likely exist. Ammonia emissions are much more uncertain, and can be part of the problem. Also suspect is the deposition rate used for nitric acid (too low) and the nighttime, heterogeneous oxidation of

NOx to nitric acid (too high), both leading to higher levels of nitrate. The reasons for having too little nitrate during the summer (e.g., no nitrate is sometimes predicted when some is observed) may be because the nitrate present is particulate nitrate formed from nitric acid attacking pre-existing particles to form a thermally stable form of particulate nitrate (e.g., soil material and salt), slight overestimates in the amount of sulfate formed or underestimates in the ammonia emissions. Monitoring has found that a significant amount of the nitrate in Class I areas outside of southern California is larger FPM or coarse, suggesting that it is formed from nitric acid attacking pre-existing aerosol forming a thermally stable form of nitrate. If this is the reason for the discrepancy, and that ammonium nitrate is not present, then the modeled sensitivity to emissions reductions will be very different than would occur. In particular, an area that might appear to be ammonia limited from the modeling, may be nitrate-limited, and most sensitive to NOx emissions.

A large error indicates that either the sensitivity to emissions changes is in error, or there is a large error in the emissions. If the latter were true, the model results could be used to scale observed levels to get a reasonably good approximation of how the ambient levels would respond. The decision was made, in advance, in SAMI to use scaling, even for the species where very good performance was found. Note, if performance is perfect, the same results are found if one uses scaling or the model results directly. Thus, the approach is asymptotically correct.

If model performance is poor, scaling the observations with model results becomes more questionable. Given the very large errors found for nitrate, the low correlation between observed and simulated levels, and that NOx emissions are relatively well known (probably well within a factor of two), the modeled sensitivity of nitrate levels to NOx emissions could be well off. Indeed, the very low observed nitrate, versus that simulated, suggest that much of the time the model is in a different regime than the actual atmosphere (e.g., the case where the two species, ammonia and nitric acid, are in sufficient supply to form aerosol nitrate vs. the case where one or both are at concentrations low enough to negate ammonium nitrate formation, and what little nitrate found is due to reactions of nitric acid with a crustal material or sea salt). Performance is worst during the winter, but during the summer there are days where no nitrate is predicted, though some is observed. In this case, NOx controls will not lead to any change in predicted nitrate, so scaling will not show any benefit. Given the performance problems, it is difficult to suggest if the sensitivity of either the annual nitrate levels, or the nitrate levels on the days with the most limited visibility, is adequately represented by the model.

One issue concerning the use of scaling is that it does not account for spatial inhomogeneities in the controls. For example, control at a specific source, even though it is a very small fraction of the total inventory, will have an enhanced local impact, though little impact further away. This issue can be dealt with by using the model to develop source-receptor relationships, and use those results to help guide the scaling.

For primary fine and coarse PM, the response of ambient PM is likely to be quite linear (though not totally due to particle growth), so scaling should work relatively well, as long as the issue of spatial inhomogeneities in the emissions controls is adequately addressed. This can be relatively easily tested using a single model simulation.

At present, the simulations have not been conducted to provide a complete source apportionment of the PM. By this, one means exercising the model to show how each source (or group of sources) impacts PM at specific receptors (e.g., the Class I areas). Such a calculation can be very helpful in suggesting controls. Further, it is important to understand the magnitude of the problem with which we are dealing, and how to interpret model results and observations. In particular, this is important for primary PM. At most Class I areas, FPM is dominated by secondary species (nitrate, ammonium, sulfate and a fraction of the OC), and primary EC and OC. Other compounds are a relatively small contributor to both FPM mass and visibility. One question, for which the model can be used to help understand, is if a significant fraction of the PM is from stationary sources. If not, i.e., that stationary sources are a small fraction of the primary PM at Class I areas, and that primary PM is a small fraction of the total PM, reductions in primary PM emissions will have a rather small impact.

Effectiveness of PM and NOx Controls on PM levels and Visibility in the West

As discussed above, nitrate is a major contributor to PM levels and visibility extinction in a few areas of the West, notably in California, and to a lesser amount the Columbia Gorge. In the southern half of California, nitrate can be the major constituent. In most other areas, nitrate is found at relatively small concentrations, around 5-20% of the total FPM. Likewise, point source primary emissions of PM, both coarse and fine, are a small contributor, regionally, as well. Thus, controls on point source emissions of NOx and PM will have a relatively limited effect on both PM and visibility in much of the West, all else being equal. The latter clause is important because, as SO2 emissions are reduced, and ammonia emissions increase (as is forecast in many areas), aerosol nitrate may become a more significant contributor, as was found in SAMI.

In and around the California valleys, nitrate formation appears to be nitrate limited. As noted above, Stockwell et al., (2000) found that one gets, roughly, about 0.6 grams of nitrate (as ammonium nitrate) per gram of NOx emissions. This would suggest that, in these areas, NO_x controls will reduce nitrate levels. The exact level of benefit will have to come from either analysis of the measurements or modeling after performance improves. The California inventory suggests that about 478 tons per day (tpd), or about 14% of the 3441 tpd statewide, of NOx come from stationary sources. Assuming that stationary sources have a similar impact on nitrate formation (SAMI results suggest this is not totally true, Odman et al., (2002)), this puts an upper bound on the likely benefits of around 15%, and the results of the SAMI study suggest that the actual impact on nitrate mass is more around 7%. This translates in to approximately 2% of the total FPM in areas around Los Angeles where nitrate makes up about 30% of the total FPM and 1% in areas of California, such as the Sierras east of the Central Valley where nitrate is about 15% of the total FPM. In other areas, the stationary source contribution, on average, would be smaller, on average. Three considerations would increase the importance somewhat: on days with the worst visibility in these areas, nitrate makes up a larger fraction of the total (in some cases, over 50%) on days with the highest levels of nitrate, a greater fractional response to NOx reductions is suggested and if the receptor is directly downwind of a major point source, the impact would be increased. The first two considerations might lead to an increased impact of up to 5%. The latter consideration would be very site and meteorology dependent.

Elsewhere in the West, nitrate levels are relatively small: usually less than a ug/m^3, and from 5-10% of the total PM. The days with the worst visibility tend to be dominated by one of three cases: high CPM and crustal (indicative of dust storms), high organic and elemental carbon (which can indicate forest fires) or high sulfate, which tends to be elevated much of the time, and increases during stagnation. Thus, unless the increasing ammonia and decreasing sulfate lead to significant nitrate increases, stationary point sources will lead to only about 2% (or less) of the visibility extinction, except in areas significantly impacted by major sources. SAMI modeling suggested that there will be small additional benefits of NOx controls in reducing sulfate due to decreased sulfur dioxide oxidation. Thus, NOx controls will have a relatively small impact on PM and visibility in the West.

The impacts of primary PM controls on point sources are more difficult to assess at this time since the available data is less specific as to the fraction of PM from point sources. As noted above, CPM has such a short lifetime that reductions will have a small impact on PM levels and visibility, except very near the source. Primary stationary source FPM, while longer lived, still appears to be relatively minor, contributing less than 0.1 ug/m^3, so controls on FPM would also have a minor impact on PM levels and visibility. This is in line with the results from studies such as those conducted at Mt. Zirkel (Watson et al., 1996). Total removal would lead to a decrease in extinction of about 0.4 Mm-1, or less than about 0.5% of the total extinction on a day with relatively bad visibility of about 20 miles.

The above analysis suggests that primary PM and NOx controls will have limited impact on visibility in the West in the near term, except in areas of California and areas directly impacted by specific stationary sources being controlled. Near-field impacts of sources needs to be conducted on a site-by-site basis. However, as sulfate levels come down, the impact of NOx controls will increase, both because nitrate levels will increase and due to the non-linear relationship between visibility and extinction. Locations whose visibility is currently dominated by sulfate may find that nitrate becomes the species of concern. Looking towards the future, it is prudent to identify the types of controls and mechanisms to increase their cost effectiveness.

Emissions Trading

Emissions trading is viewed as an economically efficient approach to air quality management, as has been experienced through the acid rain program. However, when trading pollutant emissions, the economic efficiencies tend to decrease as limits are placed on trading, e.g., spatially, temporally, across sectors, and across pollutants. There are issues associated with each. Allowing spatially diverse trades can shift emissions reductions and the resulting air quality improvements.

Temporal trading can lead to decreased (or enhanced) benefits. For example, sulfate tends to be higher in the summer due to more rapid oxidation. If the trading results in greater reductions during the winter, average sulfate levels may decrease less than if the reductions were more uniform. On the other hand, if the SO2 reductions are greater in the summer, the benefits could be enhanced. This may be more critical for nitrate which, as discussed above, is very sensitive to temperature, and is thus found predominantly in the winter. Primary emissions would not be affected as much.

Trading across source sectors may be impacted by (1) the spatial and temporal trading concerns identified above, (2) that sources can emit at different elevations above the ground, and (3) that different sectors do not have the same PM characteristics. Emissions from a tall stack are in to a very different environment than a more dispersed ground level source. First, elevated emissions, e.g., from utilities, tend to be very concentrated in NOx, and the plumes can stay very NOx rich for significant distances. Ground level sources tend to be more disperse and in to environments with higher levels of VOCs. In recent field experiments, this has been found to have an impact on ozone formation efficiencies (e.g., Ryerson et al., 2001). Recent modeling has also found this to be the case for ozone and acid deposition, and nitrate FPM (Odman et al., 2002), though the differences were not as large as that measured for ozone. For primary FPM, this is likely a small impact, though ground level FPM emitted in populated areas would likely lead to a greater exposure than if emitted higher up. It is likely that the spatial and temporal issues are of greater concern. A final concern is that trading primary PM emissions between sectors can lead to a different type (e.g., predominant size) of PM being emitted. For example, utility emissions are likely going to be more fine than, say, cement production or mining emissions (as well as being emitted at different levels). CPM deposits faster, and impacts visibility less. Thus, removing a ton of CPM would not have the same benefit as removing a ton of FPM, all else equal. In this way, trading primary PM emissions between sectors is much like trading pollutant types, with the issues discussed below.

Scientifically, the most challenging type of trade is across pollutant types, e.g., SO2 for NOx, primary PM for NOx, etc. This is because it is difficult to quantify how much of one pollutant can be traded for another and have equal air quality benefits. The possibility of displacement reactions further clouds how such trades can be weighted. For example, reducing SO2 will lead to sulfate aerosol reductions. However, this can free up ammonium to react with nitric acid, leading to increased nitrate. While this was found to be the case in SAMI modeling, the “rebound effect” was not large. Finally, the different species will have different impacts, e.g., in terms of visibility reduction. For example, each fraction of the PM has a different impact on visibility per mass. Nitrate and sulfate have a greater impact, on a per mass basis, than soil or CPM. Further, sulfate and nitrate both have a greater impact on visibility at higher humidities, other constituents do not, generally leading those two constituents to have a bigger impact on visibility on a per mass basis than (say) organics. Conversely, elemental carbon is very effective at absorbing light. If one can correctly account for the relationships between emissions and the resulting concentrations, it is straightforward to account for the visibility impairment differences, though the relationships can change with time. For example, as SO2 emissions are reduced in the future, and ammonia emissions increase, the area could become more sensitive to NOx emissions. Thus, one ton of NOx reduction may become more valuable in relationship to one ton of primary FPM.

A final issue is that reducing NOx emissions will impact both secondary sulfate and OC formation. This is because NOx is central to the formation of ozone and increasing the oxidizing capacity of the atmosphere. Modeling as part of SAMI suggested that this secondary effect is small, but non-zero, impacting mainly the formation of sulfate. Typically, reducing NOx also reduced sulfate formation slightly, but in some locations NOx reductions led to small sulfate increases due to increasing H2O2 formation and the heterogeneous oxidation of SO2, as well as increasing OH levels. In general, these secondary impacts will slightly enhance the effects of NOx emissions reductions, but can be ignored for now due to the larger uncertainties in quantifying the NOx-aerosol nitrate system response.

Given the complexities, the question arises is, if emissions trading is to be done, how should trading equity be established. If the trades are somewhat restricted to the point that there are no obvious resulting inequities (e.g., limited spatially and not across pollutants, and that there is little likelihood that there would be little temporal or elevation differences), policy makers could likely proceed without the use of some more extensive approach. However, this would severely restrict the market and the associated economic benefits. Dealing with the issues identified is ideally tackled using a comprehensive air quality modeling effort, such as is being done by the WRAP. In this case, the model could be exercised to identify the appropriate trading ratios and the inequities resulting from various trades.

A major problem at this time, as discussed above, is that confidence in a model's use can only be developed through successful evaluation and good model performance for the species of interest. In the case of the WRAP modeling, nitrate performance was poor, and it would be difficult to use such results to assess how to make trades equitable, e.g., to develop trading ratios across pollutants. While less of an issue, using the model to assess trading SO2 for FPM is also difficult because of the rebound effect. When model performance is such that the WRAP is comfortable that the model is adequately capturing the physics and chemistry affecting pollutant evolution of the compounds of interest, then the model, presumably, can be used to determine how to make trades equitable. Note, this does not mean that performance for all species has to be good. Having poor performance for crustal species would not significantly impact the use of the model for comparing SO2 and NOx trades.

Given the successes achieved from emissions trading, it is important to identify model performance problems such that trading guidelines can be established in a sound fashion. None of the issues identified above are "show stoppers". However, given the level of uncertainty in the modeling results at present, inter-pollutant trading would have the potential to jeopardize visibility improvements in the region.

Suggested Model Simulations

At present, a few sensitivity simulations have been conducted using CMAQ. While conducted, in part, to understand model performance, they are providing insight into PM dynamics in the West. In particular, the cases where NH_3 emissions are being changed to find areas that are most sensitive to NH_3 emissions. Such sensitivity calculations are key to addressing trading issues and identifying effective control strategies.

After model performance is judged to be adequate, a number of calculations are suggested. A first set of calculations is to conduct a comprehensive source apportionment by source type (e.g., point, area and mobile), pollutant (SO2, NO_x, NH_3, CPM and FPM), and location (e.g., state or region). The resulting matrix (a total of about 45 sensitivities) can be used to guide trading, assessing the impact of transport, identifying important source regions to pristine areas, and guiding control simulations. While 45 simulations may appear prohibitive, various tools exist to facilitate the process. For example, SAMI used DDM-3D. The results of these sensitivities should be stratified into days with very good and poor visibility, and the annual average. The aggregation of days will tend to suggest a more local impact of sources than looking at a typical day.

A second set of simulations would be to explore specific control issues, e.g., the imposition of certain sets of controls. A particular interest would be to explore future PM levels as the NO_x and SO2 emissions are decreased, but NH_3 emissions increase. The interest would be to assess if there is the possibility of increased nitrate formation due to the higher NH_3 and lower sulfate in spite of lower NOx emissions, as was found in the SAMI study. In some areas, this may lead to nitrate replacing sulfate as the major contributor to visibility reduction, greatly increasing the impact of NO_x controls on visibility.

A third calculation would look at how SCR or SNCR controls would impact visibility in a point source plume. The ammonia in such a plume might lead to locally increased ammonium nitrate formation. While, regionally, ammonia emissions from such control technologies are small compared to animal waste decomposition and fertilizer, on a very local scale there may be increased PM formation. Such a calculation may require a finer grid being employed in locations to capture the finer scale impacts of the plume where, presumably, both NO_x and NH_3 would be elevated.

Summary

The states that are part of the WRAP have a very diverse chemical/PM “climatology”, represented by extremes ranging from the dry, high nitrate areas in Southern California to the wet, low PM northern coastal mountains, to the dry mountains and deserts inland. Typically, the major constituents of the visibility-impairing PM are fine PM sulfate, OC and, at times, nitrate, though there are episodes of high coarse material.

Doing a simple, approximate, mass-lifetime balance on coarse PM emissions from primary sources suggests that, on average, primary CPM emissions from point sources will contribute a very small fraction of the total PM. This is borne out in the observations. Near the source (within a few 10s of km), however, the sources may be significant. FPM is much longer lived than CPM, and is predominantly secondary, being composed primarily of sulfate, OC and nitrate.

Primary FPM from point sources is estimated to be a small contributor to FPM mass and light extinction on a regional basis. First, the total amount is small relative to other components of the FPM. Second, it has a lower impact, on a per mass basis, than other constituents. Third, periods of highest extinction do not appear to have significant amounts of point source-derived, primary FPM as compared to the other components, particularly CPM during dust storms, organic and elemental carbon during fires, sulfate during stagnation events, and nitrate in areas of high ammonia.

Nitrate is formed from emissions of NO_x that react to form nitric acid, which then can undergo gas-to-particle conversion. Much, but not all, of the nitrate is fine, and higher observed concentrations are formed from the reaction between nitric acid and ammonia to form ammonium nitrate. A fraction of the nitrate will be formed from nitric acid attacking pre-existing PM (coarse or fine). Ammonium nitrate levels can be reduced by either reducing nitric acid formation or ammonia emissions, with the greatest sensitivity to reducing the precursor that is least abundant (on a mole basis). Thus, some parts of the region will be ammonia-limited, others will be nitrate-limited (e.g., areas with high ammonia, such as near confined feeding and intense agricultural operations). The fraction that is formed from nitrate attacking pre-existing PM will not be very ammonia sensitive, responding more to NO_x controls. Modeling currently suggests that much of the domain is ammonia-limited (in terms of nitrate formation). However, CMAQ does not include the capability to simulate the nitric acid attacking pre-existing PM, so this may be an artifact. What this suggests is that it is important to get model performance to the point where one is confident that the nitrate formation mechanisms are quantitatively reliable.

In areas where nitrate formation is nitric acid-limited, NO_x controls will generally reduce PM (with a few local exceptions). However, one ton of emissions reductions will not lead to one less ton of PM being formed. NO, NO_2 and nitric acid all deposit out (dry or wet). Indeed, nitric acid deposits very rapidly, and simulations suggest that most of the mass will be removed this way. The WRAP model can develop the response of nitrate PM to NOx emissions.

Trading emissions of primary FPM from one source to another would be relatively straightforward compared to other types of trades. The relative height of emission will have little impact on far downwind receptors. As with trading any type of emissions, trades across sources in very different locations may lead to one area receiving greater air quality benefits than another. Trading emissions of point source CPM would be especially sensitive to location in that the major impact is very near the source, dropping dramatically within 10 km.

NOx emissions trading to reduce PM formation would be more complex. First, as noted above, some (if not most) regions are likely ammonia-limited, so NOx controls will have relatively smaller impacts on nitrate than might be expected. Second, the oxidation of NOx to nitric acid will depend on emission height and the intensity of emissions (e.g., the concentration of NOx in a plume). Third, reducing NOx will slightly impact the formation of sulfate and OC. Further complicating the issue is that an equitable trade (in terms of visibility) today may not be equitable in the future. Again, trading across large spatial areas may lead to issues in terms of which areas benefit most.

Trading between pollutants is more involved yet, and a major concern is that the relationship between NOx emissions and nitrate formation is not well quantified at present. As model performance improves, there is no reason that it would not be practical to use the model to set trading relationships between pollutants. In so doing, one must account for the differing impact on visibility on a mass basis and the response to humidity.

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SECTION V:
SUMMARY OF AIR QUALITY MODELING RESULTS

Context

The modeling performed for this report is best described as a "sensitivity analysis." The intent is to get a preliminary assessment of the general atmospheric response to changes in NOx and PM emissions from stationary sources. A secondary objective is to "practice" this type of modeling to get a better understanding of the key technical issues and to identify the most effective ways at evaluating and displaying model results. The results presented here are the best available predictions at this time, but forthcoming improvements to the modeling system may affect the results in ways that alter the policy implications. For this reason, results are discussed in a fairly broad and qualitative manner – i.e., spatial patterns and relative changes. As the modeling system improves and specific strategies are contemplated, additional emission scenarios will be designed and modeled.

Modeling System

The WRAP's regional-scale air quality modeling system used to support other aspects of the Section 309 plans was also used to provide information for this report. A description of the modeling system – in addition to model performance statistics, input files, and detailed model results – is available at http://pah.cert.ucr.edu/rmc.

Emission Scenarios

Three emission scenarios were simulated:

- A 50 percent decrease in NOx emissions from plants with NOx emissions > 100 tpy,
- A 50 percent decrease in PM_{10} emissions from plants with PM_{10} emission > 100 tpy, and
- A 25 percent increase in NOx and PM_{10} emissions from all stationary sources.

The first two scenarios are meant to address the regional haze rule's requirement to "assesses emissions control strategies for stationary source NOx and PM, and the degree of visibility improvement that would result from such strategies." As discussed in Section VI of this report, many commercially-available technologies (and various combinations of such technologies) are capable of achieving a 50% or greater NOx emission reduction without having to switch fuels. Hence, the 50% reduction, although intended primarily to gauge the general atmospheric response to NOx reductions, is not an unreasonable level of control to assume for this exercise in terms of technical feasibility. Again with technical (and administrative) feasibility in mind, emission reductions were limited to plants with emissions greater than 100 tpy, similar to the approach in the Annex. The third scenario is meant to address the rule's requirement to "evaluate and discuss the need to establish emission milestones for NOx and PM to avoid any net increase in these pollutants from stationary sources within the transport region." Hence, a 25 percent increase from all stationary sources was assumed to simulate potential growth in the economy and/or disproportionate growth in high-emitting sectors such as energy development, fossil-fueled electricity generation, and mineral processing.

For reasons implied in the rule, the emission changes in the scenarios described above were limited to the nine-state GCVTR[12]. Also, the emission changes were applied to the 2018 inventory, which includes reductions expected from full implementation of the Annex. This provides a basis for comparing results to other strategies being modeled by the WRAP.

Model Performance and Future Improvements

Nitrate concentrations are poorly predicted by the current modeling system, especially in the winter. For this reason, results for nitrate (and all other species) for the NOx and PM sensitivity runs are only presented for the three month period of July – September.

Several aspects of the modeling system are being improved and evaluated, which should improve confidence in future model predictions, both in the summer and winter. These improvements and evaluations involve the chemical mechanisms, the ammonia inventory, a more robust meteorological database (2002 vs 1996), enhanced grid resolution (12 km vs 36 km), plume-in-grid capabilities, the introduction of an inventory for wind-blown dust emissions, and better temporal allocation and chemical speciation of point and area source emissions. A source apportionment mechanism is also expected to be included with the model.

Model Results

As stated above, results are presented in a fairly broad and qualitative manner – i.e., spatial patterns and relative changes. Relative (percent) changes are of particular interest because their errors are believed to be smaller than those of the absolute concentrations. It is not clear how the seasonal limitation of this analysis (July – September) may affect the relative changes, but it is likely to reduce them to some extent. First, nitrate concentrations tend to be lower in the summer than in the winter, especially in areas where nitrate concentrations are highest and the potential for change the greatest. Second, results are averaged over a full three-month period. Typically, visibility effects are measured by averaging conditions over the worst 20 percent of the days observed per year at an ambient monitoring site, which is approximately 22 days. But in this analysis, because it is limited to the July-September timeframe, the results are averaged over 92 consecutive days and do not represent a measure of the worst conditions, again when the potential for change is the greatest. Thus, while there are many uncertainties surrounding the model's nitrate predictions, the limitation of this study to July – September will tend to limit the apparent impacts from the NOx (and to some extent) PM_{10} emission changes.

On a ton-per-ton basis, reductions in stationary source PM_{10} emissions appear to yield greater regional haze benefits than reductions in NOx emissions. For instance, when stationary source PM_{10} emissions are reduced by 98,000 tpy (a 50 percent reduction from GCVTR facilities > 100 tpy), the average summer-time visibility improvement across all Class I areas in the GCVTR (in Mm^{-1}) is about 0.4 percent. When stationary source NOx emissions are reduced by

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[12] In 1996, stationary sources in the GCVTR emitted about 75 percent and 83 percent of the NOx and PM_{10} emissions, respectively, in the13-state WRAP region.

412,000 tpy (a 50 percent reduction from GCVTR facilities > 100 tpy), the visibility improvement is only somewhat greater, at 0.5 percent.[13] Hence, on a purely technical basis (without considering existing controls, costs, or other implementation issues), reductions in PM emissions might be more effective at improving regional haze than reductions in NOx emissions.

Nevertheless, the 50 percent NOx reduction scenario tends to produce slightly greater regional haze benefits than the 50 percent PM_{10} reduction scenario. This is because stationary sources comprise 33 percent of the total NOx inventory but only 7 percent of the total PM_{10} inventory. So even though much of the NOx is never converted to the particulate phase, the sheer volume of NOx emission reductions relative to PM_{10} reductions and the fact that nitrate (mostly in the fine mode) scatters light more efficiently than primary PM (mostly in the coarse mode) make the NOx reduction scenario more meaningful in terms of regional haze benefits than the PM_{10} reduction scenario. The fact that stationary source NOx emissions are not as well controlled as stationary source PM_{10} emissions in the West actually lends some relevance to the outcome that NOx emissions are altered more in the sensitivity analysis than PM_{10} emissions.

For the three-month summer period examined in this analysis, NOx changes have very little effect on aerosol concentrations beyond changes in nitrate. Other species that could be indirectly affected – e.g., ozone concentrations and subsequent oxidation of SO_2 and organic gases into the particulate phase – do not appear influenced by the levels of NOx reductions (16 percent of the total inventory) assumed in this analysis. This finding may change after implementing all the model improvements noted above, but since nitrate currently appears as the largest responder to NOx changes, and given the information above regarding the NOx and PM scenarios, the maps, tables, and discussion below place somewhat more emphasis on nitrate and the results of the 50 percent NOx reduction scenario than on other species and scenarios.

Figures V-1 and V-2 show the model-predicted 2018 base case (Annex included) surface-layer concentrations of ammonium nitrate (NH4NO3) and PM_{10}, respectively, averaged over the three month period of July-September. The values in these maps should not be construed as the *expected* ammonium nitrate and PM_{10} concentrations in 2018, which are determined by scaling the ambient monitoring data by the relative changes predicted by the model. Rather, these maps are intended to provide a sense of the spatial variability and span of concentrations, which are useful for interpreting the following maps of relative (percent) changes – e.g., a high percentage change in a low-concentration area may be less meaningful than a moderate percentage change in a high concentration area.

Figures V-3 and V-4 show the absolute and percentage change, respectively, in NH4NO3 concentrations from a 50 percent reduction in stationary source NOx emissions from facilities in the GCVTR greater than 100 tpy. The largest absolute changes occur in southern CA, where concentrations in Class I areas are predicted to decrease by 0.15 to 0.25 ug/m^3. A second area of reductions is predicted in the central-east Rocky Mountains, especially in north-central CO. Although the reductions are not as large as in southern CA (0.04 to 0.11 ug/m^3), they are larger than average across the domain and exhibit the largest percentage reduction (10 to 20 percent).

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[13] In some Class I areas, the visibility improvement can be two to five percent on some days.

It is interesting to compare these results with those simulating the effects of the SO_2 backstop emissions trading program, or Annex. In the case of the Annex, an SO_2 emission reduction of 15 percent (132,000 tons) in the GCVTR produced a sulfate reduction of 4 percent averaged across all Class I areas in the GCVTR on the 20% worst modeled days. In the case of the NOx sensitivity run, a NOx emission reduction of 15 percent (412,000 tons) in the GCVTR produced a nitrate reduction of 5 percent averaged across all Class I areas in the GCVTR on the July-September modeled days. The nitrate reduction does not produce as much visibility benefit at most Class I areas because its concentrations are much smaller, but the response of nitrate to NOx reductions is similar in proportion to the response of sulfate to SO_2 reductions.

Figures V-5 and V-6 show the absolute and percentage change, respectively, in NH4NO3 concentrations from a 25 percent increase in stationary source NOx and PM_{10} emissions from all stationary sources in the GCVTR. The spatial pattern of changes is very similar to that in the 50 percent NOx reduction scenario, although the magnitude of changes are about half. Again, it is interesting to see some proportionality in the modeling results – i.e., an emission change that is half as large produces aerosol changes that are about half as large. The percent increase in NH4NO3 concentrations and visibility impairment (in Mm^{-1}) in this scenario is 2 percent and 0.5 percent, respectively, when averaged over all Class I areas in the GCVTR for July-September.

Figures V-7 and V-8 show the absolute and percentage change, respectively, in PM_{10} concentrations from a 50 percent reduction in stationary source PM_{10} emissions from facilities in the GCVTR greater than 100 tpy. Maximum reductions in PM_{10} are about 0.1 to 0.5 ug/m^3, or about 4 to 8 percent. Compared to the NOx reduction scenario, reductions in ambient PM_{10} are more dispersed, with a greater number of local maximums. This may reflect the fact that there are a fewer number of large PM_{10} sources than large NOx sources and that much of the PM_{10} emissions are coarse particles, with shorter transport distances.

Figures V-9 and V-10 show the absolute and percentage change, respectively, in PM_{10} concentrations from a 25 percent increase in stationary source NOx and PM_{10} emissions from all stationary sources in the GCVTR. The spatial pattern of changes reflects where both relatively large NH4NO3 changes (southern CA and central-east Rockies) and PM_{10} changes (additional areas) are predicted. The largest PM_{10} increases are about 0.1 to 0.3 ug/m^3, or 2 to 3 percent. Less than half of this is NH4NO3.

Table V-1 shows the predicted change in light extinction and NH4NO3 at each Class I area in the GCVTR averaged over the July-September period as a result of reducing NOx emissions by 50 percent from stationary sources with emissions greater than 100 tpy in the GCVTR.[14] As shown in the maps, the greatest impacts occur in southern CA, followed by areas in CO. The average improvements in light extinction in these areas is about 0.3 to 1.5 Mm^{-1} (1 to 2.5 percent). The average improvement in NH4NO3 is about 0.05 to 0.25 ug/m^3 (3 to 20 percent).

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[14] Tabular, site-specific data for other scenarios is available upon request. Tabulay presentation of results was limitted to this scenario since others tend to produce smaller changes in visibility.

Figure V-1. Base Case Ammonium Nitrate Concentrations (μg/m^3) – for purposes of illustrating spatial patterns, not magnitudes.

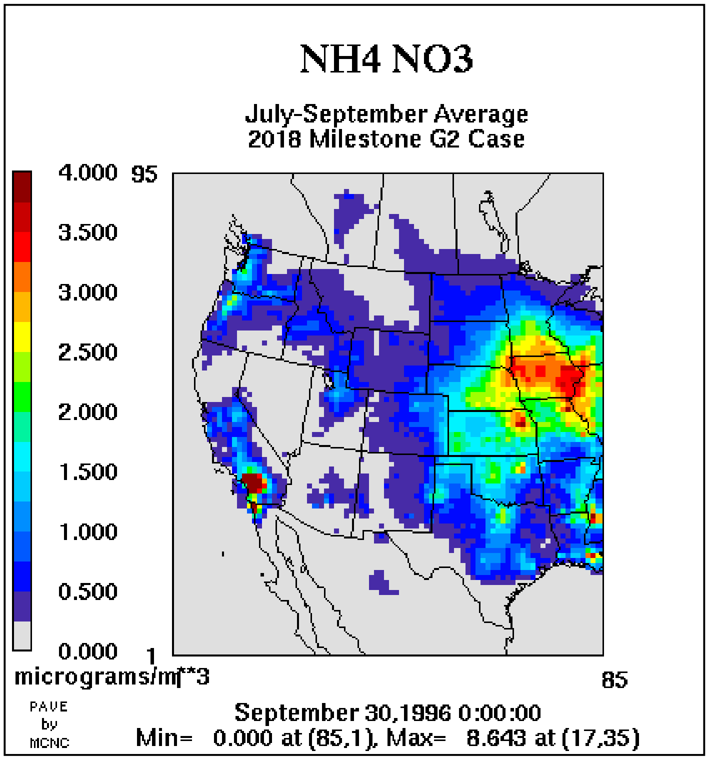

Figure V-2. Base Case PM$_{10}$ Concentrations (μg/m^3) – for purposes of illustrating spatial patterns, not magnitudes.

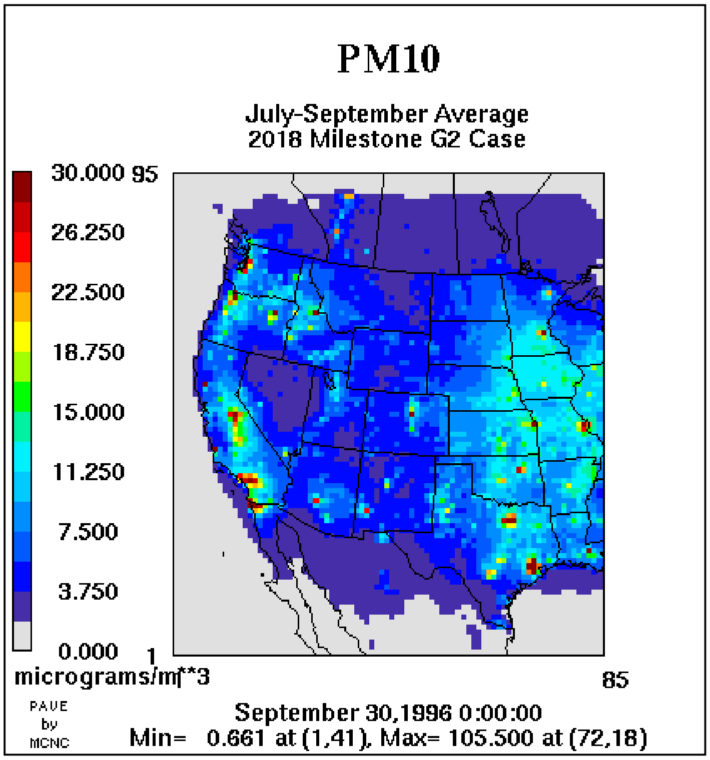

Figure V-3. Change in Ammonium Nitrate Concentrations Resulting from a 50% Reduction in Stationary Source NOx Emissions > 100 tpy.

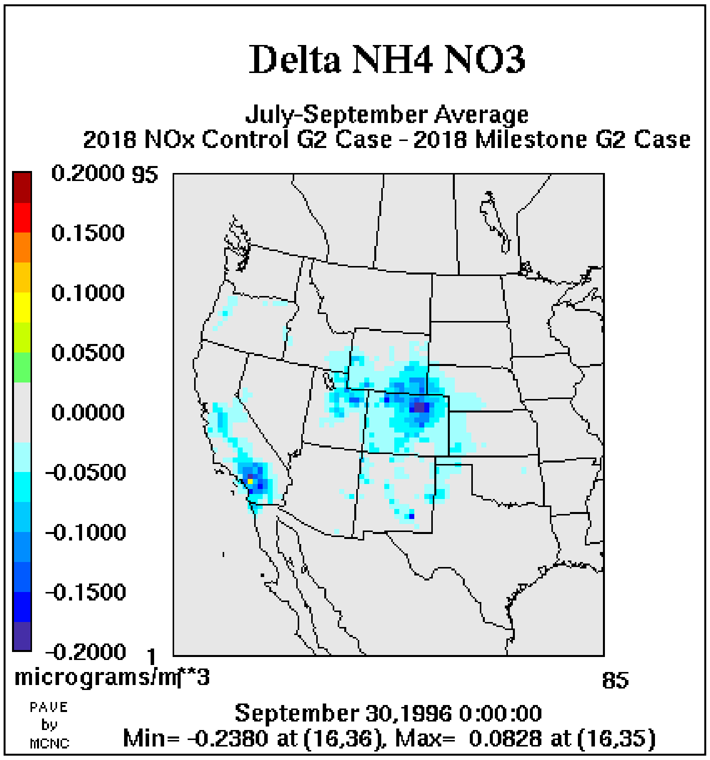

Figure V-4. Relative Change in Ammonium Nitrate Concentrations Resulting from a 50% Reduction in Stationary Source NOx Emissions > 100 tpy.

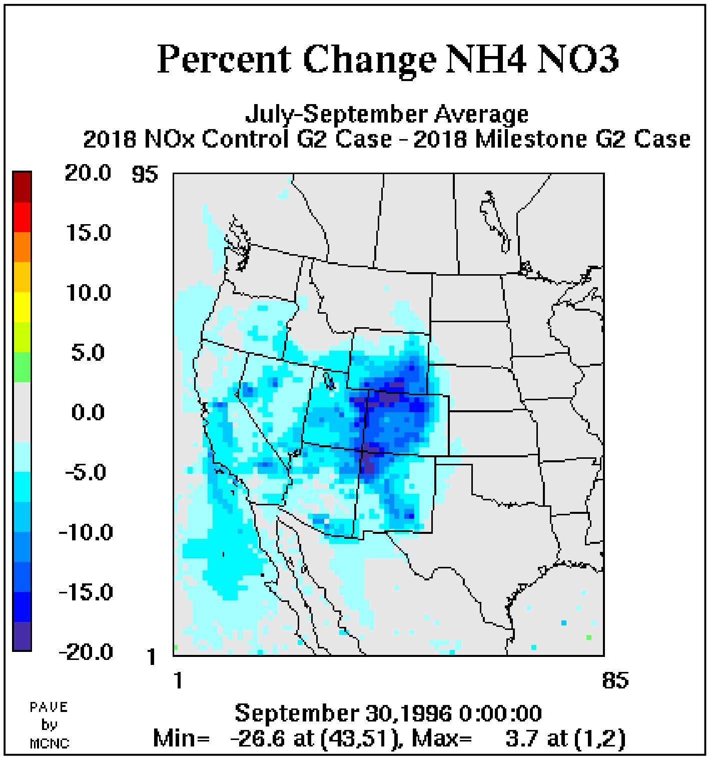

Figure V-5. Change in Ammonium Nitrate Concentrations Resulting from a 25% Increase in Stationary Source NOx and PM_{10} Emissions.

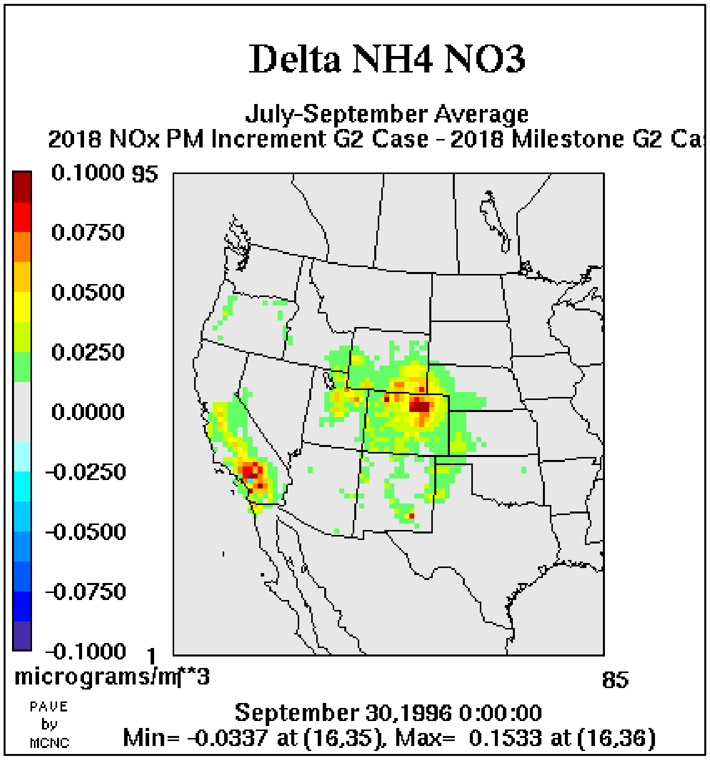

Figure V-6. Relative Change in Ammonium Nitrate Concentrations Resulting from a 25% Increase in Stationary Source NOx and PM_{10} Emissions.

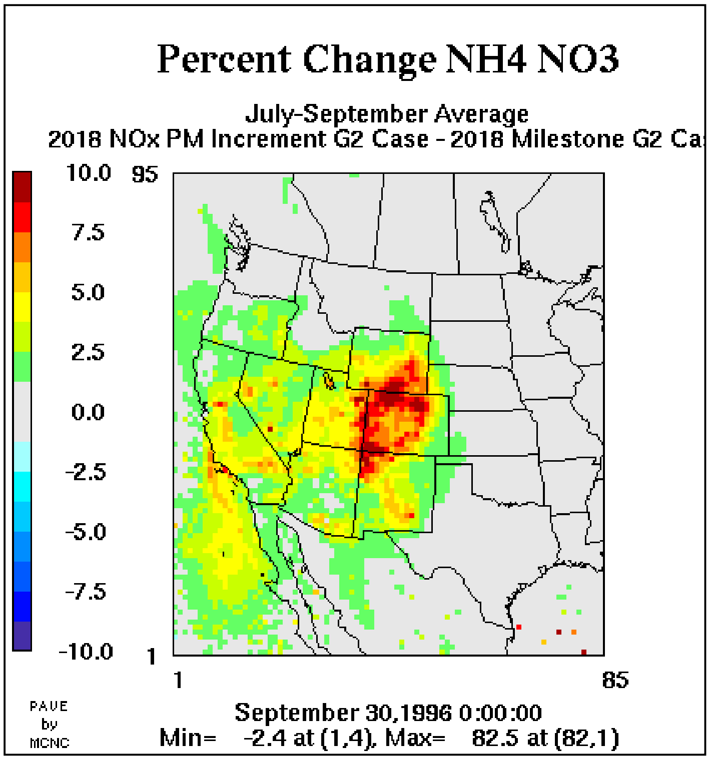

Figure V-7. Change in PM_{10} Concentrations Resulting from a 50% Reduction in Stationary Source PM_{10} Emissions > 100 tpy.

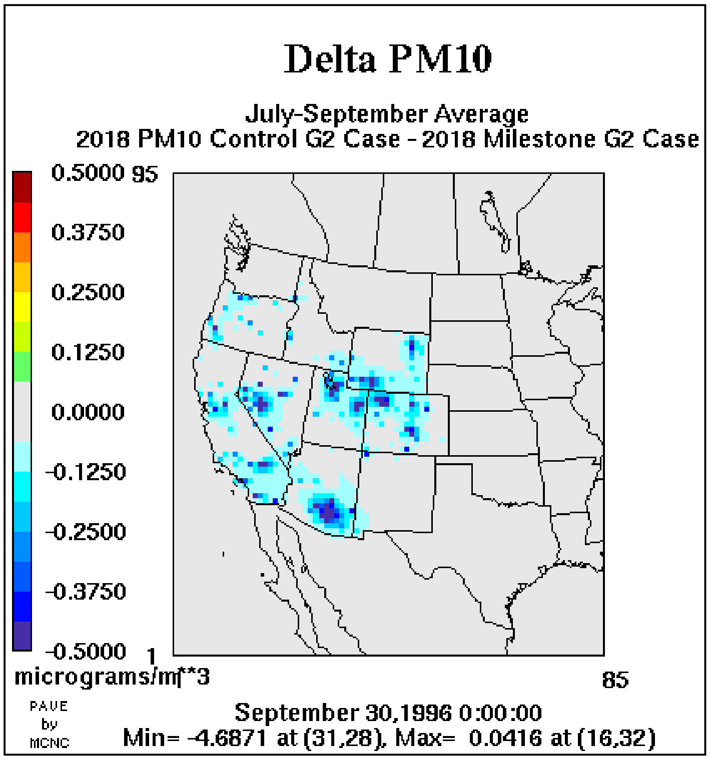

Figure V-8. Relative Change in PM_{10} Concentrations Resulting from a 50% Reduction in Stationary Source PM_{10} Emissions > 100 tpy.

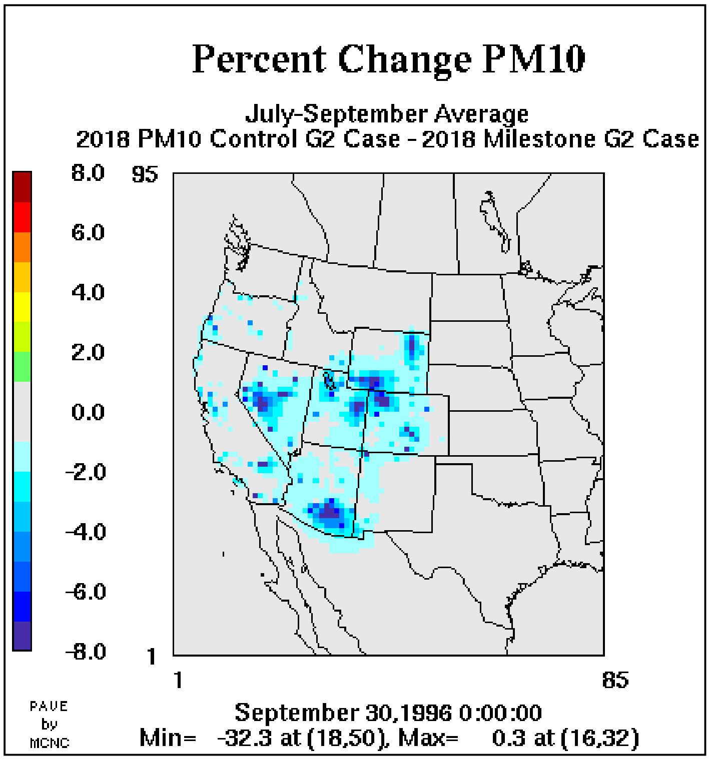

Figure V-9. Change in PM$_{10}$ Concentrations Resulting from a 25% Increase in Stationary Source NOx and PM$_{10}$ Emissions.

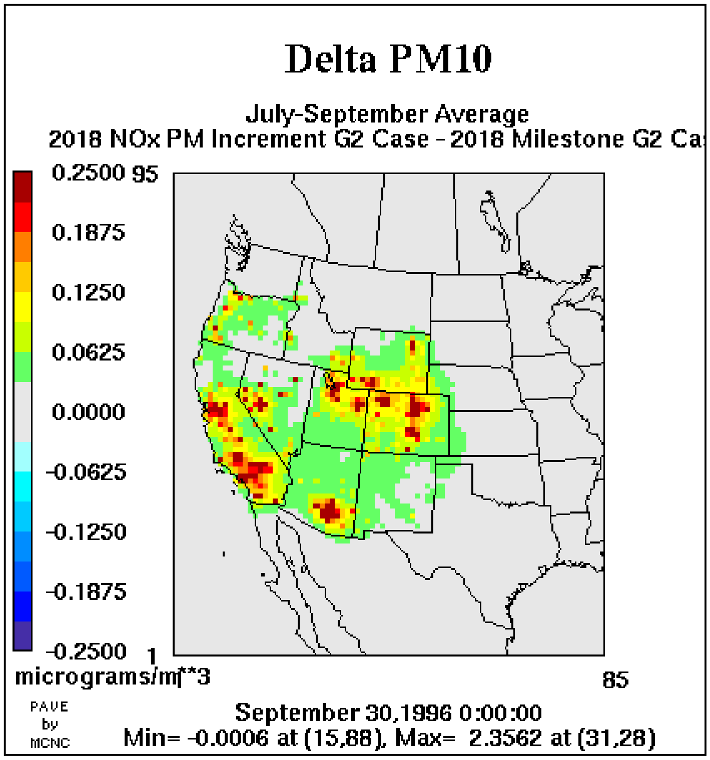

Figure V-10. Relative Change in PM$_{10}$ Concentrations Resulting from a 25% Increase in Stationary Source NOx and PM$_{10}$ Emissions.

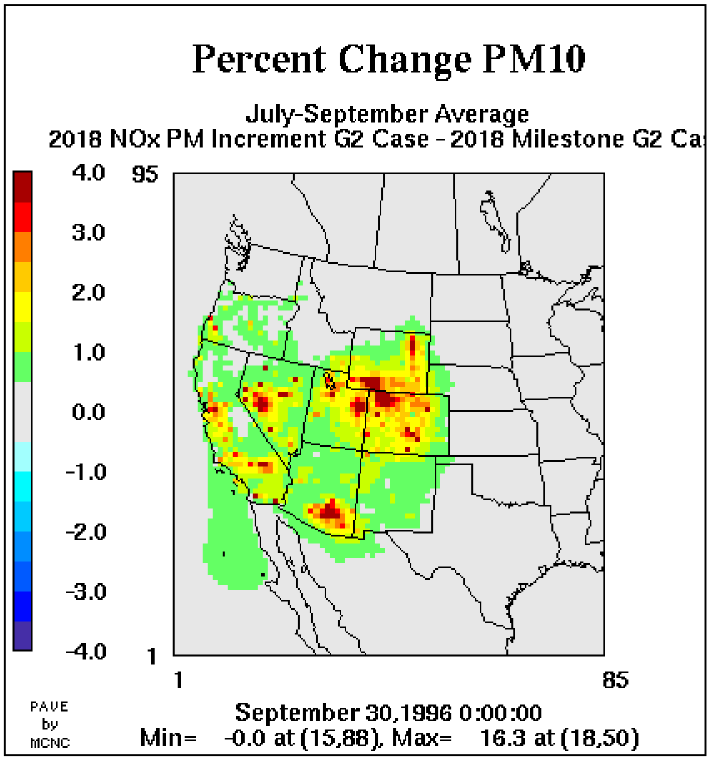

Table V-1. Light Extinction and Ammonium Nitrate Changes Resulting from a 50% Reduction in Stationary Source NOx Emissions > 100 tpy, Sorted by Average Light Extinction.

		Light Extinction		NH4NO3	
State	**GCVTR Class I Area**	**Δ Mm^{-1}**	**Δ %**	**Δ $\mu g/m^3$**	**Δ %**
CA	Cucamonga Wilderness	-1.59	-1.37	-0.25	-3.25
CA	San Jacinto Wilderness	-1.13	-1.18	-0.19	-2.97
CA	San Gabriel Wilderness	-0.83	-0.82	-0.13	-3.06
CA	Agua Tibia Wilderness	-0.81	-1.05	-0.12	-2.77
CA	San Gorgonio Wilderness	-0.80	-0.93	-0.16	-2.65
CO	Rawah Wilderness	-0.69	-2.41	-0.11	-16.84
CO	Mount Zirkel Wilderness	-0.61	-2.28	-0.09	-20.86
CO	Rocky Mountain NP	-0.57	-1.68	-0.09	-14.14
CA	Joshua Tree NP	-0.47	-0.77	-0.13	-3.69
CO	Eagles Nest Wilderness	-0.45	-1.41	-0.07	-11.97
CO	Great Sand Dunes NM	-0.43	-1.57	-0.06	-13.87
NM	White Mountain Wild.	-0.36	-1.11	-0.05	-10.51
CO	Flat Tops Wilderness	-0.34	-1.28	-0.05	-13.82
CO	La Garita Wilderness	-0.34	-1.27	-0.05	-12.15
CO	West Elk Wilderness	-0.33	-1.19	-0.05	-12.09
CO	Black Canyon of Gunnison	-0.31	-0.97	-0.04	-14.83
CO	Weminuche Wilderness	-0.29	-1.14	-0.04	-13.02
CO	Maroon Bells-Snowmass	-0.29	-1.00	-0.04	-10.62
CA	Dome Land Wilderness	-0.27	-0.46	-0.04	-4.48
CA	Pinnacles NM	-0.26	-0.86	-0.04	-5.93
NM	Wheeler Peak Wilderness	-0.24	-0.91	-0.03	-8.94
AZ	Mount Baldy Wilderness	-0.22	-0.64	-0.03	-6.25
NM	Salt Creek Wilderness	-0.22	-0.71	-0.02	-7.75
AZ	Petrified Forest NP	-0.21	-0.73	-0.01	-6.88
WY	Bridger Wilderness	-0.20	-0.77	-0.03	-7.51
CA	Hoover Wilderness	-0.20	-0.19	-0.04	-2.60
CA	Emigrant Wilderness	-0.19	-0.25	-0.03	-3.08
NM	Gila Wilderness	-0.18	-0.34	-0.02	-3.81
CA	Minarets	-0.18	-0.23	-0.03	-2.71
OR	Mount Jefferson Wild.	-0.17	-0.28	-0.02	-2.59
NM	San Pedro Parks Wild.	-0.17	-0.64	-0.02	-10.43
NM	Bandelier NM	-0.17	-0.58	-0.02	-7.42
AZ	Superstition Wilderness	-0.16	-0.40	-0.02	-2.04
OR	Mount Washington Wild.	-0.16	-0.30	-0.02	-2.55
OR	Mount Hood Wilderness	-0.14	-0.22	-0.03	-1.83
CA	Kaiser Wilderness	-0.14	-0.19	-0.02	-2.63
CA	Kings Canyon NP	-0.14	-0.22	-0.02	-2.83
CA	John Muir Wilderness	-0.14	-0.23	-0.02	-2.69
CA	San Rafael Wilderness	-0.14	-0.32	-0.01	-5.40
AZ	Sierra Ancha Wilderness	-0.13	-0.35	-0.01	-1.76
CA	Sequoia NP	-0.13	-0.24	-0.02	-4.56
CA	Yosemite NP	-0.13	-0.17	-0.02	-2.63
UT	Arches NP	-0.13	-0.51	-0.01	-14.82

		Light Extinction		NH4NO3	
State	**GCVTR Class I Area**	**Δ Mm^{-1}**	**Δ %**	**Δ μg/m^3**	**Δ %**
NM	Pecos Wilderness	-0.12	-0.44	-0.03	-7.29
WY	Fitzpatrick Wilderness	-0.12	-0.46	-0.02	-4.83
NM	Bosque del Apache Wild.	-0.12	-0.44	-0.01	-8.65
OR	Kalmiopsis Wilderness	-0.11	-0.34	-0.01	-3.05
OR	Eagle Cap Wilderness	-0.11	-0.31	-0.02	-4.29
OR	Three Sisters Wilderness	-0.11	-0.24	-0.02	-2.55
AZ	Grand Canyon NP	-0.11	-0.40	-0.01	-7.36
UT	Capitol Reef NP	-0.11	-0.45	-0.01	-8.21
WY	Grand Teton NP	-0.11	-0.36	-0.02	-3.47
WY	Teton Wilderness	-0.10	-0.36	-0.02	-3.56
OR	Crater Lake NP	-0.10	-0.21	-0.01	-2.09
ID	Hells Canyon Wilderness	-0.10	-0.13	-0.02	-3.87
OR	Strawberry Mountain Wild.	-0.10	-0.15	-0.01	-2.89
AZ	Sycamore Canyon Wild.	-0.10	-0.32	-0.01	-5.25
CA	Marble Mountain Wild.	-0.10	-0.23	-0.01	-2.57
AZ	Chiricahua NM	-0.10	-0.36	0.00	-6.65
AZ	Chiricahua Wilderness	-0.10	-0.36	0.00	-6.65
AZ	Galiuro Wilderness	-0.10	-0.30	-0.01	-4.30
UT	Canyonlands NP	-0.09	-0.42	-0.01	-10.61
OR	Diamond Peak Wild.	-0.09	-0.18	-0.01	-2.20
AZ	Saguaro Wilderness	-0.09	-0.28	-0.01	-6.84
UT	Bryce Canyon NP	-0.08	-0.32	-0.01	-6.14
AZ	Pine Mountain Wild.	-0.08	-0.24	-0.01	-2.82
AZ	Mazatzal Wilderness	-0.08	-0.23	-0.01	-2.82
NM	Carlsbad Caverns NP	-0.08	-0.26	-0.01	-4.03
OR	Mountain Lakes Wild.	-0.07	-0.18	-0.01	-2.43
UT	Zion NP	-0.07	-0.21	-0.01	-7.22
CO	Mesa Verde NP	-0.07	-0.21	-0.03	-17.68
CA	Lava Beds Wilderness	-0.06	-0.15	-0.01	-2.09
WY	Yellowstone NP	-0.06	-0.20	-0.01	-2.50
CA	South Warner Wilderness	-0.06	-0.19	-0.01	-3.77
ID	Selway-Bitterroot Wild.	-0.05	-0.12	-0.01	-2.19
WY	North Absaroka Wild.	-0.05	-0.19	-0.01	-2.43
WY	Washakie Wilderness	-0.05	-0.19	-0.01	-2.43
CA	Point Reyes NS	-0.05	-0.15	0.00	-2.80
ID	Craters of The Moon Wild.	-0.04	-0.14	-0.01	-3.89
OR	Gearhart Mountain Wild.	-0.04	-0.13	0.00	-2.24
CA	Caribou Wilderness	-0.04	-0.11	0.00	-3.38
CA	Thousand Lakes Wild.	-0.03	-0.09	0.00	-2.30
CA	Lassen Volcanic NP	-0.03	-0.07	0.00	-2.28
CA	Yolla Bolly Middle Eel Wild.	-0.03	-0.09	0.00	-1.13
NV	Jarbridge Wilderness	-0.03	-0.13	0.00	-4.49
CA	Ventana Wilderness	-0.02	-0.12	0.00	-5.24
CA	Redwood NP	-0.02	-0.06	0.00	-2.92
	Average	-0.21	-0.51	-0.03	-5.79

SECTION VI:
SUMMARY OF EMISSION CONTROLS AVAILABLE FOR LARGE STATIONARY SOURCES OF NOx AND PM

Final Report

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LIST OF ACRONYMS, ABBREVIATIONS AND SYMBOLS

ACFM	Actual cubic feet per minute
AFBC	Atmospheric fluidized bed combustor
BART	Best available retrofit technology
DLN	Dry Low NO_x
EIA	Energy Information Administration
EPA	United States Environmental Protection Agency
GCVTC	Grand Canyon Visibility Transport Commission
GCVTR	Grand Canyon Visibility Transport Region
FGR	Flue Gas Recirculation
Hg	Mercury
ICE	Internal Combustion Engine
LEC	Low Emission Combustion
LNB	Low-NO_x burner
MBtu	Millions of British Thermal Units
MTF	Market Trading Forum
NG	Natural Gas
NO_x	Nitrogen oxides
NSCR	Non-selective catalytic reduction
NSPS	New Source Performance Standard
O&M	Operating and Maintenance
OFA	Overfire air
PM	Particulate matter
PM10	Particulate matter less than 10 microns
PM2.5	Particulate matter less than 2.5 microns
SCC	Source Classification Code
SCR	Selective catalytic reduction
SIP	State Implementation Plan
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
TPY	Tons per year
WGA	Western Governors' Association
WRAP	Western Regional Air Partnership

ACKNOWLEDGEMENTS

We are grateful to Dr. Praveen Amar for providing help in locating the most recent sources of information on control technologies, as well as for external review of the report from the perspective of making it relevant to readership in the state governments/regional entities.

1 INTRODUCTION

1.1 Background

The Western Regional Air Partnership (WRAP) has undertaken a program to assess emissions control technologies and strategies for large stationary sources of NO_x and PM emissions in the western states region. The WRAP is a collaborative effort of tribal governments, state governments, and various federal agencies to implement the recommendations of the Grand Canyon Visibility Transport Commission (GCVTC) and to develop the technical and policy tools needed by western states and tribes to comply with the U.S. Environmental Protection Agency's (EPA) Regional Haze Rule.

The WRAP established the Market Trading Forum (MTF), in large part, to develop and recommend emission control strategies for stationary sources of air pollution. A major focus of the MTF has been the establishment of regional emission milestones for sulfur dioxide (SO_2) and a regional backstop cap-and-trade program for SO_2 to be triggered if the milestones are not met voluntarily.

The MTF is also responsible for generating a report required in 40 CFR 51.309(d)(4)(v) of the Regional Haze Rule. The report must assess emission control technologies and strategies for stationary source NO_x and PM emissions and the degree of visibility impairment that would result from such strategies. It must also evaluate the need for NO_x and PM milestones to avoid any net emissions increase and to support possible multi-pollutant and multi-source control programs. Finally, this year several states must submit state implementation plans (SIPs) to EPA and must commit to a 2008 revision containing any necessary long-term strategies and Best Available Retrofit Technology (BART) requirements for stationary source NO_x and PM.

This project is essentially a starting point for addressing stationary source NO_x and PM emission sources over the next four years, at which point local and/or regional emission control program(s) may be implemented. Future work by the WRAP will investigate these issues further and will attempt more detailed cost estimates and emission reductions achievable in the WRAP region given the nature of its sources and existing controls.

1.2 Objectives

The main objectives of this project are to identify and briefly describe for large stationary sources in the western United States:

- The universe of modern commercially-available or near-available stationary source NO_x and PM controls (either technologies or best management practices);
- Trends in such controls;
- Their approximate capital and operating costs, control efficiencies, and cost effectiveness;
- Secondary environmental impacts, such as control of other air pollutants and generation of solid or hazardous waste;
- Real-world experience at facilities implementing or testing such controls;

- Future opportunities for improvements and demonstrations; and
- Recommendations for future work.

1.3 Definitions and Methodology

The work plan for the project consisted of the following tasks:

Task 1. Inventory of Stationary Sources in the WRAP Region. This task involved a review of the 1996 WRAP stationary source emissions inventory (version 3, in MS Access format), as well as other recent and relevant databases to determine the number/type of stationary sources with emissions greater than 100 tons per year (TPY) and the type and performance of air pollution control devices installed on those sources. Two subsets were created for NO_x and PM emissions, respectively, based on the following criteria:

- Sources (defined as emission units, or records, in the database) having annual emissions of the pollutant of interest greater than 100 TPY; and
- Sources located in the thirteen-state region: AZ, CA, CO, ID, MT, ND, NM, NV, OR, SD, UT, WA, WY (See Figure 1).

Table 1 lists the fields extracted from the WRAP database.

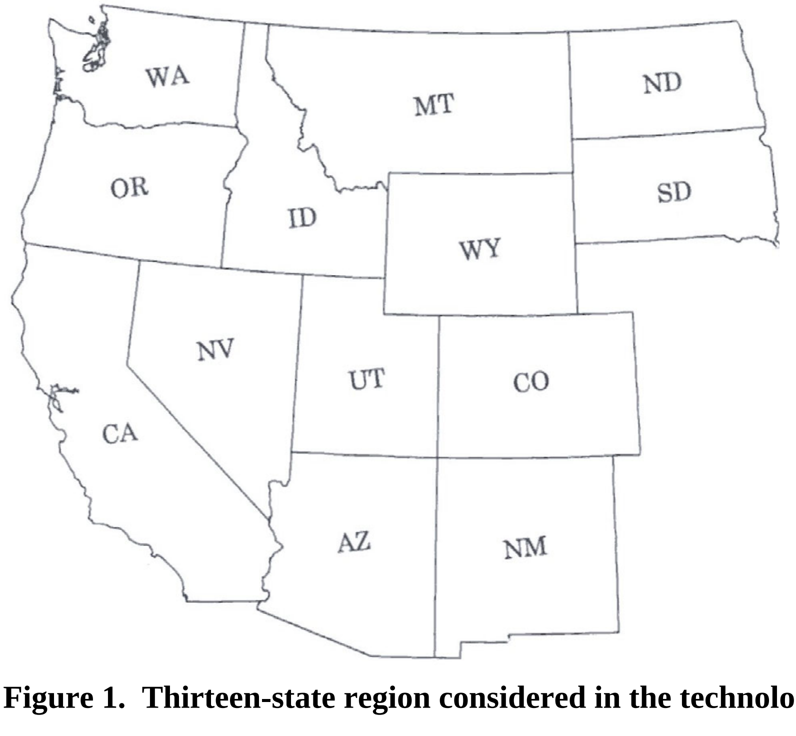

Figure 1. Thirteen-state region considered in the technology assessment.

Table 1. WRAP database fields used in the technology assessment.

Field	Description
FIPST	FIP State Code
POINTID	NAPAP Point ID Code
STACKID	Stack Number
BLRID	Boiler ID Code Code (utility only)
SEGMENT	Segment Number
ORISID	ORIS Plant ID (utility only)
PLANT	Plant Name
SCC	Source Classification Code
SCC1_DESC	General category (e.g., External Combustion Boiler)
SCC3_DESC	Major industrial group within general category
SCC6_DESC	Specific industry or emission source
SCC8_DESC	Particular emitting process or fuel type
NOX_ANN	Annual NO_x Emissions, tons per year
PM10_ANN	Annual PM Emissions, tons per year
CO_ANN	Annual CO Emissions, tons per year
SO2_ANN	Annual SO_2 Emissions, tons per year
NOX_CPRI	Primary Control Equipment Code - NO_x
PM_CPRI	Primary Control Equipment Code - PM
CONTROL_DEVICE_DESC	Control Device Description (either NO_x or PM)

Note: Codes taken from the 1996 National Emission Trends (NET) PC Inventory File Format

The source classification codes (SCCs) used to categorize sources served as general guidelines for choosing the categories in Task 1. The similarities (or differences) in the control technologies applicable to specific SCCs were also factors in grouping sources. For example, a category called “Coal-fired boilers” was created containing emissions data from utility and industrial boilers (of different boiler types) burning coal because the same NO_x and PM control technologies can be applied to most of these sources. With this in mind, Table 2 gives the categories created for characterization of the WRAP emissions and a description of the WRAP categories (i.e., SCC codes) used to define the categories in this report.

For electric utility point sources, additional databases were used to determine boiler capacity (MBtu/yr), enhance and update information on control technologies in place, and verify other source information. These databases were: EPA CEMs database for 1996 and 2001 [1], EPA E-GRID database for 1996 and 2000 [2] and the EIA-767 database for 1996 [3].

The results of Task 1 are discussed in Section 2 of this report.

Table 2. List of Categories Used to Characterize Point Sources

Category	**WRAP Sources (based on SCC Codes contained with the category)**
Coal-Fired Boilers	All coal-fired external combustion boilers
Reciprocating Engines	All reciprocating ICE’s
NG	*Natural gas-fired ICE’s, including 2- and 4-cycle*
Diesel	*Diesel-fired ICE’s, including large-bore engines*
Process Gas	*Unspecified process gas-fired ICE’s*
Cement Kilns	All cement kilns (wet and dry process)
Oil/NG Boilers	External combustion boilers firing oil or natural gas
Turbines	All fired turbines
NG	*Natural gas-fired turbines*
Diesel	*Diesel-fired turbines*
Mineral Processing	Cement crushing, grinding and drying, asphalt, other drying applications
Petrochemical	Flares, cat.crackers, nitric acid plants, unspecified process gas operations, *does not include process heaters*
NG Compressor	Technology (reciprocating engine or turbine) not specified
Pulp and Paper	Recovery boilers, lime kilns, drying and smelting
Wood Boilers	Wood waste and/or bark boilers, technology unspecified
Refinery Process Heaters	Process heaters
Glass Manufacture	Glass melting furnaces
Primary Metal Production	Electric arc furnaces, reheat furnaces, material handling and unspecified
Waste Combustion	Liquid waste (Dakota gasifier) and solid waste (WTE)
Refinery	Unspecified refinery emissions
In-process Fuel Use	Unspecified combustion systems at glass and cement plants
Jet Engine Testing	Jet engine testing
Oil and Gas Production	Flares and unspecified processes
Smelting Operations	Copper and aluminum smelting
Sugar Beet Processing	Sugar beet processing
Secondary Metal Production	Steel foundries
Turbines, Steam	Geothermal power production

Task 2. Survey and Documentation of Emission Control Technologies. In this task, we focused on the identification and compilation of control technologies for NO_x and PM (main focus) and for SO_2 and Hg (secondary focus). Sources identified in Task 1 that represented minor contributions to the emissions profile of the region, either due to their small number, uniqueness, or size, were considered in a more cursory fashion if their control technology options fell outside of the range of the more common/available technologies. This effort consisted mainly of literature reviews, on-line searches and personal (telephone) contacts and interviews.

The following information was collected on each technology or process:

- Type and fundamentals of technology or process;
- Projected performance;
- Costs (capital and O&M or cost effectiveness in $/ton of pollutant removed) or cost projections;
- Status of development and opportunities for or barriers to further development; and
- Applicability to category (or categories) of WRAP sources identified in Task 1.

The results of this task are presented in Sections 3 and 4.

Task 3. Control Technology Analysis and Discussion. This task was the main focus of the project, in which a thorough evaluation and discussion of the many identified technologies was conducted. A summary containing the following information was created for each technology:

- Process name
- For each source category to which the technology was applicable, the following information was tabulated:
    - Total annual NO_x or PM emissions from sources greater than 100 TPY
    - Percentage NO_x and PM reduction
    - Cost ($/ton or $/ACFM)
    - Development status
- Detailed descriptions were prepared for the following:
    - Process description
    - Achievable NO_x or PM reduction
    - Cost information
    - Development status
    - Practical considerations
    - Compatibility with other air pollution control technologies
    - Secondary environmental impacts
- References

The results of this task are presented in Appendices C and D.

Task 4. Final Report. The draft version of the final report was submitted to WRAP on 25 April 2003. The final report was submitted on 30 June 2003.

2 NO_x AND PM SOURCES IN THE WESTERN UNITED STATES

2.1 Characterization of NO_x Sources

Table 3 gives the annual NO_x emissions in the GCVTR as well as in thirteen-state region for sources (defined as emission units, or records, in the WRAP database) exceeding 100 TPY. The cut-off of 100 TPY captures 84% of the stationary source NO_x emissions in the WRAP database for the thirteen-state region. Figure 2 shows the distribution of annual NO_x emissions (greater than 100 TPY) as a function of state.

The largest source category by far in the thirteen-state region is coal-fired boilers (69%); the top five categories (coal-fired boilers, internal combustion engines, cement kilns, turbines and oil and natural gas boilers) account for almost 90% of the NO_x emissions. Therefore, this report concentrates on control technologies applicable to these major process categories.

The states with the largest NO_x emissions are AZ, CA, ND, NM, UT, and WY. Since all these states except ND are in the GCVTR, it is not surprising that emissions from the nine states in the GCVTR (AZ, CA, CO, ID, NM, NV, OR, UT, WY) account for 75% of the thirteen-state emissions greater than 100 TPY. Appendix A contains NO_x emissions by process category and by state.

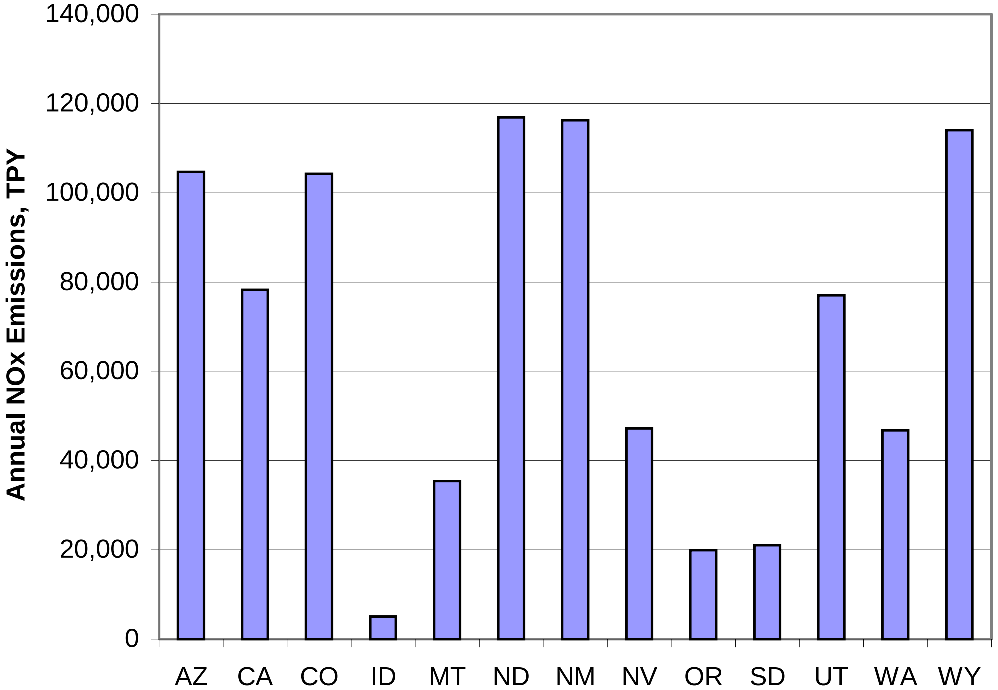

Figure 2. Annual NO_x emissions from sources with emissions greater than 100 TPY for the thirteen-state region.

Table 3. A comparison of annual emissions of NO_x from sources with emissions greater than 100 TPY between the thirteen-state region and the GCVTR.

	13-States		GCVTR		
Category	**# Units**	**Total NO_x TPY (>100 TPY)**	**# Units**	**Total NO_x TPY (>100 TPY)**	**% NO_x in GCVTR**
Coal-Fired Boilers	151	607,748	117	436,882	72%
Reciprocating Engines	423	86,210	394	78,092	91%
Cement Kilns	39	41,009	31	32,503	79%
Oil/NG Boilers	112	32,910	80	26,116	79%
Turbines	86	25,278	78	23,955	95%
Mineral Processing, Other	34	16,250	25	13,342	82%
Petrochemical	48	13,719	31	8,326	61%
NG Compressor	16	10,959	16	10,959	100%
Pulp and Paper	39	10,010	20	4,619	46%
Wood Boilers	48	9,776	36	6,864	70%
Refinery Process Heaters	38	9,311	29	7,302	78%
Glass Manufacture	14	5,033	12	4,379	87%
Primary Metal Production	17	3,476	16	3,360	97%
Waste Combustion	6	3,309	2	339	10%
Fugitive	8	3,256	8	3,256	100%
In-process Fuel Use	9	2,605	8	2,016	77%
Fixed Wing Aircraft	4	2,297	4	2,297	100%
Oil and Gas Production	7	1,140	5	792	70%
Smelting Operations	3	961	2	852	89%
Food and Agriculture	3	730	1	111	15%
Secondary Metal Production	4	507	0	0	0%
Turbines, Steam	1	165	1	165	100%
Total (> 100 TPY)	**1,110**	**886,659**	**916**	**666,527**	**75%**

With few exceptions, the distribution of NO_x sources is similar in the thirteen-state region as compared to the GCVTR. ICE's (reciprocating engines and turbine) are predominantly in the GCVTR, while pulp and paper emissions are mostly outside the GCVTR. As a result of this similarity, the scope of this project was expanded to include additional WRAP states at minimal cost.

The achievable NO_x emission rate depends on the fuel type. For coal-fired boilers, lower NO_x emission rates are obtained when firing subbituminous coal as compared to bituminous coal. Thus, it is useful to look at the distribution of coals in use in the thirteen-state region. Figure 3 shows the distribution of coals burned in utility boilers as a function of boiler type and coal rank. Most coal burned in the West is burned close to the mine; this distribution of coal rank reflects the native coals in the West.

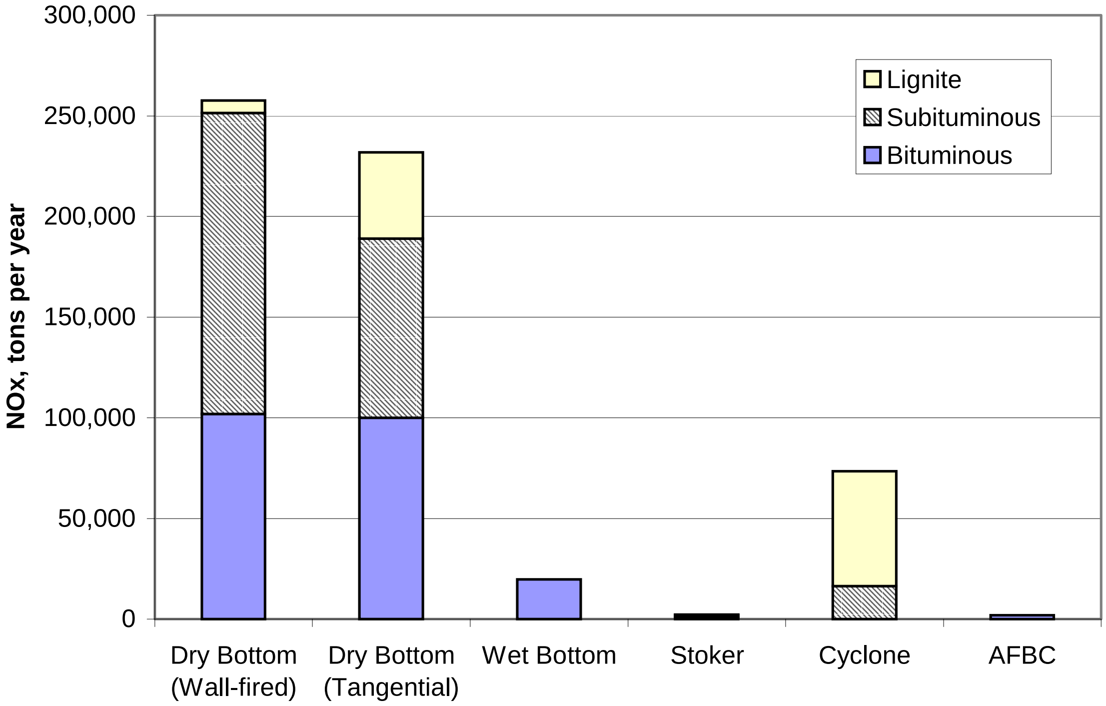

Figure 3. NO_x emissions from coal-fired utility boilers as a function of boiler type and coal rank for thirteen-state region from WRAP 1996 database.

For ICE's, the application of NO_x control technology can depend on the type of fuel. More so than with utility boilers, the design and operation of the engine is often determined by the primary fuel. Most of the stationary ICE's with annual emissions greater than 100 TPY burn natural gas, as shown in Figure 4.

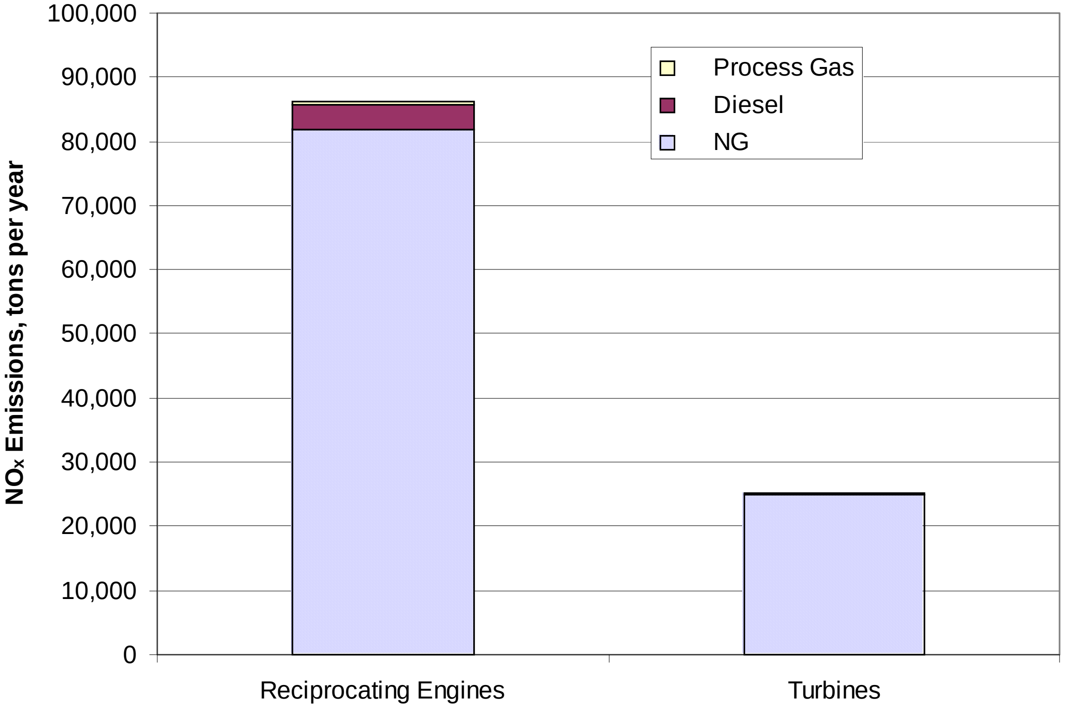

Figure 4. NO_x emissions from Internal Combustion Engines as a function of engine type and fuel for thirteen-state region from WRAP 1996 database.

As long as a source category consists of primarily large sources, the cut-off of 100 TPY will include most of the NO_x emission sources. The 100-TPY cut-off captures 84% of the NO_x emissions in the WRAP database as a whole. However, certain source categories contain a very large number of small sources. For ICE's (reciprocating engines and turbines) the 100-TPY cut-off only captures about 56% of the emissions as shown in Figures 5 and 6, although this is by far the second largest source category of stationary source NO_x emissions. Thus, NO_x control programs for sources in this category will require careful consideration of population attributes (e.g., controlling a large number of small sources).

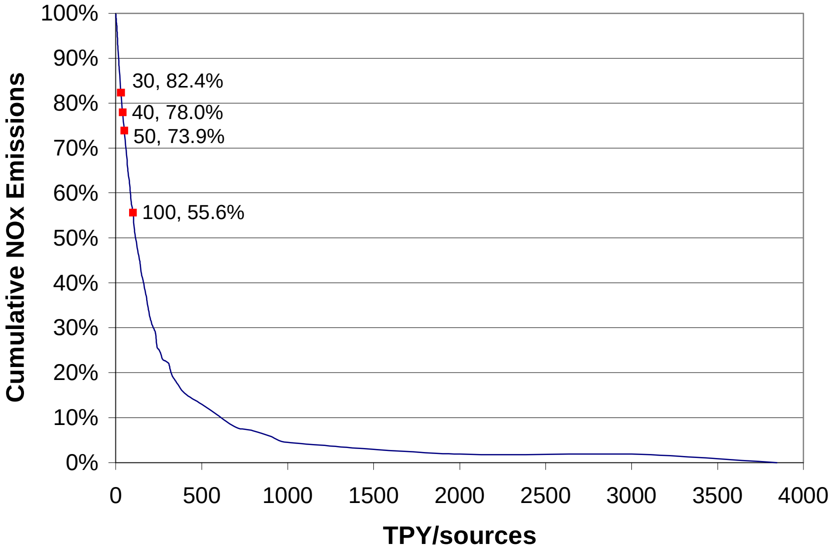

Figure 5. Cumulative NO_x emissions from ICE's in the thirteen-state region as a function of annual emission per source.

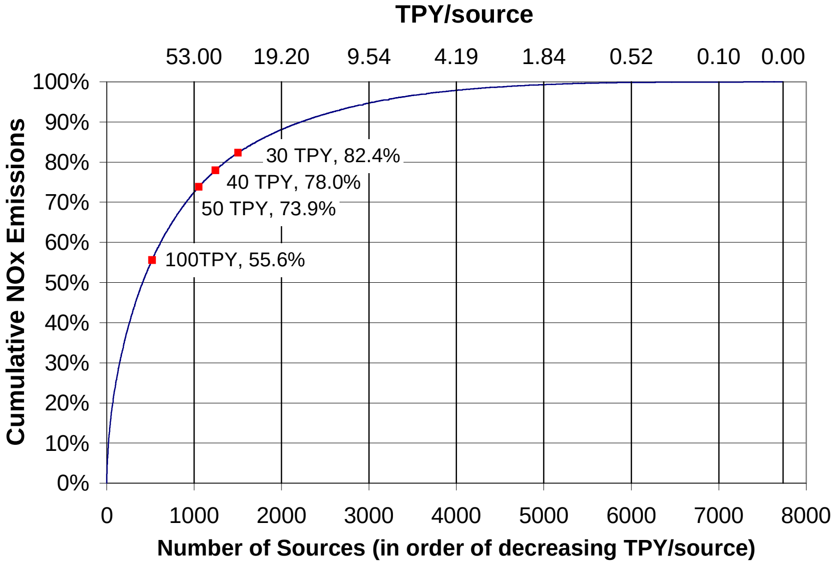

Figure 6. Cumulative NO_x emissions from ICE's in the thirteen-state region as a function of number of sources (in order of decreasing annual emission per source.)

The 1996 WRAP database contains information on control technologies for the pollutants of interest. According to the 1996 data for sources greater than 100 TPY, few sources had NO_x controls, as shown in Table 4. Overall, just above 4% of the NO_x sources greater than 100 TPY in the WRAP 1996 database had installed controls. Coal-fired boilers were the most frequently controlled (15% of the units), followed by petrochemical processes (about 13% of the units). Note that control technologies listed in the right-hand column are as reported in the WRAP database. In a few cases, the description of the control technology does not seem correct (e.g., fabric filter or electrostatic precipitator) for NO_x control; this is a limitation of the data available and it is outside the scope of this program to determine the accuracy of the data in the WRAP database.

Table 4. NO_x Control Technologies in use in 1996 on Sources Greater than 100 TPY from 1996 WRAP database.

Category	**# Units**	**Units Controlled**	**Total NO_x TPY**	**Avg NO_x TPY/Unit**	**NO_x Control Technology** (number of applications in parentheses)
Coal-Fired Boilers	151	23	607,748	4,025	Ammonia Injection(2), Fluid Bed Dry Scrubber(1), Low Excess Air Firing(3) , Modified Furnace Or Burner Design(13), Misc.(4)
Reciprocating Engines	423	3	86,210	204	Catalytic Reduction(1), Process Change(2)
Cement Kilns	39	2	41,009	1,052	Electrostatic Precipitator – High Efficiency(2)
Oil/NG Boilers	112	4	32,910	294	Low Excess Air Firing(3), SNCR(1)
Turbines	86	5	25,278	294	Steam Or Water Injection(5)
Mineral Processing	34	1	16,250	478	Fabric Filter - High Temperature, i.e. T>250F(1)
Petrochemical	48	6	13,719	286	Catalytic Afterburner(1), Catalytic Afterburner With Heat Exchanger(1), Catalytic Reduction(1), Staged Combustion(2), Tray-Type Gas Absorption Column(1)
NG Compressor	16	0	10,959	685	None
Pulp and Paper	39	0	10,010	257	None
Wood Boilers	48	1	9,776	204	Ammonia Injection(1)
Refinery Process Heaters	38	0	9,311	245	None
Glass Manufacture	14	0	5,033	360	None
Primary Metal Production	17	1	3,476	204	Process Enclosed(1)
Waste Combustion	6	0	3,309	552	None
Refinery	8	0	3,256	407	None
In-process Fuel Use	9	0	2,605	289	None
Jet Engine Testing	4	0	2,297	574	None
Oil and Gas Production	7	0	1,140	163	None
Smelting Operations	3	0	961	320	None
Sugar Beet Processing	3	0	730	243	None
Secondary Metal	4	0	507	127	None
Turbines, Steam	1	0	165	165	None
Total	**1,110**	**46**	**886,660**	**799**	

2.2 Comparison with Other Databases for NO_x Control Technologies

The level of control for coal-fired boilers in the WRAP database seemed low, even for 1996. Therefore, the 1996 WRAP database was compared with the data available for utility boilers in the 1996 CEMS and E-GRID databases. The EIA-767 database was also searched for NO_x control technologies. The E-GRID database should contain the information in the other two databases since it contains data from 24 different federal data sources, including EIA data and other EPA data. Only coal-fired utility boilers were included in this comparison, not all coal-fired boilers. However, only 3% of the WRAP NO_x emissions from coal-fired boilers in the thirteen-state region were from non-utility boilers.

It is worthwhile to take a closer look at utility boilers for two reasons. First, they are by far the largest source of NO_x emissions, accounting for 68% of the emissions from sources greater than 100 TPY. Second, the effectiveness of NO_x control technologies on boilers depends on the type of the boiler as well as on the fuel burned.

For this exercise, the EPA databases (CEMs and E-GRID) were queried to obtain information on capacity (MBtu per year) and control technologies. Data from 1996 was used in order to compare with the WRAP 1996 database. EPA and WRAP records were matched using ORIS Plant ID numbers and plant names. For matching records, control technologies not listed in the WRAP database were added, capacity (MBtu) entries were added, and NO_x emissions were replaced from the EPA databases.

A comparison of Tables 5 and 6, which contain, respectively, the WRAP data and the WRAP data augmented by the other databases, shows that the combination of the WRAP data and the EPA and EIA data suggests that 44% of the utility boilers had NO_x control (in 1996), as compared to only 12% when considering only the WRAP data by itself. The EPA databases probably undergo a more thorough QA/QC procedure than was used to create the WRAP database. Thus, the E-GRID and other federal databases might be expected to have more complete information.

Table 5. NO_x Emissions and Control Technologies for Utility Boilers in the Thirteen-State Region from WRAP 1996 Database.

	Number of Units	Controlled Units	NOx Emissions (TPY)	Average Emissions (Tons/Source)	NO_x Control Technology
Dry Bottom	99	14	489,580	4,945	Modified Furnace/Burner Design (13), Low Excess Air Firing(1)
Cyclone	5	1	73,468	14,694	Low Excess Air Firing(1)
Wet Bottom	2	0	19,688	9,844	None
NG Boiler	48	3	18,813	392	Low Excess Air Firing(3)
Stoker	6	0	1,779	296	None
Coal-fired AFBC	2	1	1,954	977	None
Wood Boiler	2	0	598	299	None
Oil Boilers					None
Total	**164**	**19**	**605,881**	**3,694**	

Table 6. NO_x Emissions and NO_x Control Technologies for Utility Boilers in the Thirteen-State Region from WRAP 1996 Database Combined with EPA and EIA Databases.

	Number of Units	Controlled Units	NOx Emissions (TPY)	Average Emissions (Tons/Source)	NO_x Control Technology
Dry Bottom	100	45	538,003	5,380	Modified Furnace/Burner Design(13) , Low Excess Air Firing(1), Low NOx Burner(21), OFA(3), Misc.(7)
Cyclone	5	1	73,528	14,706	Low Excess Air Firing(1)
Wet Bottom	3	3	23,409	7,803	Low NOx Burner(3)
NG Boiler	47	22	19,917	424	Low Excess Air Firing(3), SCR(2), SNCR(3), Misc.(14)
Stoker	6	0	3,987	665	None
Coal-fired AFBC	2	2	1,954	977	Low Excess Air Firing(1), Misc.(1)
Wood Boiler	3	0	957	319	None
Oil Boilers	1	0	110	110	None
Total	**167**	**73**	**661,866**	**3,963**	

The achievable NO_x emission rate depends on the boiler-fuel combination. The largest general class of utility boilers (in terms of number and capacity) is the dry bottom boiler. Dry bottom boilers can further be subdivided into wall-fired and tangential. Natural gas boilers emit less NO_x than coal-fired boilers per unit of fuel consumed. Of coal-fired boilers, tangential-fired units have the lowest emission rate and cyclones have the highest. The controls in the WRAP database are almost entirely low-NO_x burners or other combustion modifications. Figure 7 compares the range of NO_x emission rates for all boilers and fuels.

Application of low-NO_x burners and other combustion modifications can reduce NO_x emissions significantly; this can be seen in the large range of NO_x emission that is due, in part, to the use of NO_x controls on some of the boilers in each subset. Substantial NO_x reductions can also be achieved on coal-fired boilers just with combustion modifications.

Since 1996, low-NO_x burners have continued to improve; currently there are vendors who will guarantee NO_x emissions as low as 0.15 lb/MBtu from low-NO_x burners or low-NO_x firing systems. Furthermore, options have been developed for other combustion modifications, and SCR has begun to be applied to coal-fired boilers. Thus, the potential for NO_x control on coal-fired boilers is significantly better today than in 1996.

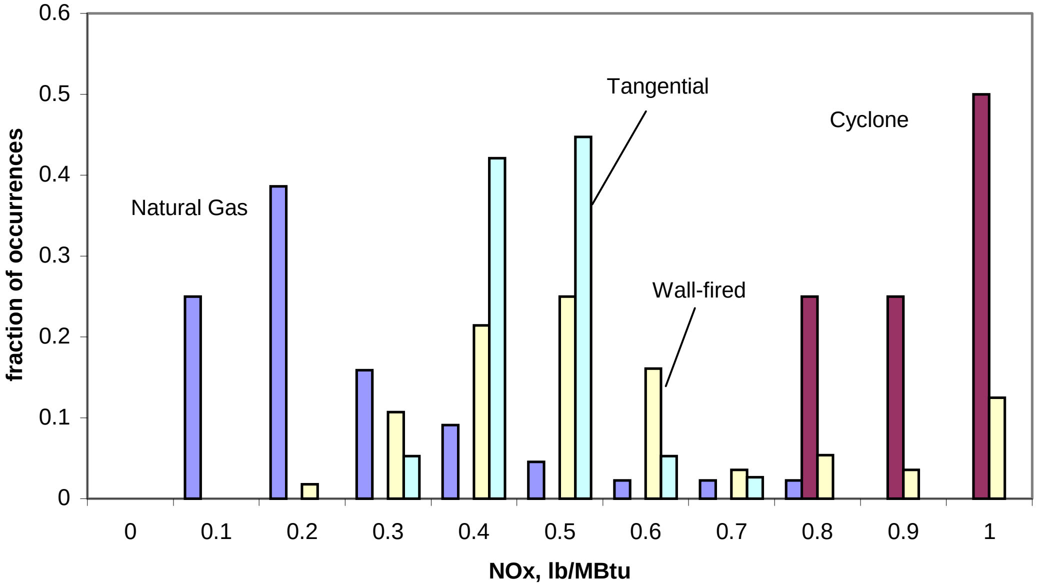

Figure 7. Distribution of NO_x emission rates for utility boilers in the thirteen-state region, combination of WRAP and EPA/EIA databases for 1996.

2.3 Trends in NO_x Emissions and Controls for Coal-Fired Utility Boilers, 1995-2000.

The most recent data available from the EPA databases for electric utility boilers are from 2000. In this section, we compare the 1996 data on NO_x emissions and controls discussed in the previous section with data from 2000.

Table 7 presents the data for 2000 derived from the EPA E-GRID and CEMS databases; this should be compared with Table 6 for 1996. The capacity of electric utility boilers increased by 37%, from 3,019,873,933 MBtu/yr in 1996 to 4,130,818,353 MBtu/yr in 2000, but the total NO_x emissions decreased by 7%. Figure 9 shows that the average annual emissions from dry bottom coal boilers (the largest category) decreased. Overall there was a decrease in emissions and an increase in the number of units that were controlled.

The number of sources increased, particularly the number of natural gas boilers, which increased from 47 to 82. The percent of natural gas boilers having NO_x controls decreased from 47% to 30%. During the time from 1996 to 2000, low-NO_x burners were added to natural gas units; there was also a small increase in SCR and SNCR on these types of boilers.

NO_x control on dry-bottom boilers increased from 47% to 71% from 1996 to 2000, resulting in a 9% decrease in total NO_x emissions from these boilers. The number of units with low-NO_x burners doubled. Overfire air (OFA) installations, though small in number, tripled. There were no SCR or SNCR installations on coal-fired boilers in 2000.

Thus, there was a modest reduction in NO_x emissions from electric utility boilers from 1996 to 2000, accompanied by a substantial increase in generating capacity. NO_x control increased, particularly on coal-fired boilers. The added NO_x control technologies were primarily low-NO_x burners and OFA.

Table 7. NO_x Emissions and NO_x Control Technologies for Utility Boilers in the Thirteen-State Region combined with EPA and EIA Databases for 2000.

	Number of Units	Controlled Units	NOx Emissions (TPY)	Average Emissions (Tons/Source)	NO_x Control Technology
Dry Bottom	96	68	489,680	5,101	Modified Furnace/Burner Design(13), Low Excess Air Firing(1), Low NOx Burner(41), OFA(9), Misc.(4)
Cyclone	5	2	66,013	13,203	Low Excess Air Firing(1), OFA(1)
NG Boiler	82	25	39,381	480	Low Excess Air Firing(4), Low NOx Burner(8), OFA(4), SCR(5), SNCR(4)
Wet Bottom	2	2	14,159	15,519	Low NOx Burner(2)
Coal-fired AFBC	2	2	2,118	1,059	Low Excess Air Firing(1), Misc.(1)
Wood Boiler	2	0	598	299	None
Stoker	1	0	335	335	None
Oil Boilers	1	0	216	216	None
Total	**191**	**99**	**612,500**	**3,207**	

2.4 Characterization of Sources of Particulate Matter (PM)

Table 8 gives the annual PM emissions for all PM sources in the thirteen-state region with emissions greater than 100 TPY. The cut-off of 100 TPY captures 60% of the PM emissions in the 1996 WRAP database for the thirteen-state region. With few exceptions, the distribution of PM sources is similar in the thirteen-state region as compared to the GCVTR. (Primary metal production emissions are mostly outside the GCVTR.) As a result of this similarity, the scope of this project was expanded to include additional WRAP states at minimal cost.

The largest source category (for those sources with emissions greater than 100 TPY) in the thirteen-state region is coal-fired boilers (40%); the top eight categories account for 92% of the PM emissions. Therefore, this report will focus on control technologies applicable to these process categories.

The state with the largest PM emissions is WY, followed by AZ, ID, and NM (Figure 9). Since all these states are in the GCVTR, it is not surprising that emissions from the nine states of the GCVTR (AZ, CA, CO, ID, NM, NV, OR, UT, WY) account for 83% of the total stationary source emissions greater than 100 TPY, as shown in Figure 10. Appendix B contains PM emissions by process category and by state.

Table 8. Annual Emissions of PM from Sources with Greater than 100 TPY.

Category	**13-States**		**GCVTR**		
	# Units	**Total PM TPY (>100 TPY)**	**# Units**	**Total PM TPY (>100 TPY)**	**% PM in GCVTR**
Coal-Fired Boilers	88	46,010	67	35,137	76%
Mineral Processing	85	24,499	75	21,824	89%
Petrochemical	42	10,836	37	9,716	90%
Wood Boilers	24	5,718	20	5,210	91%
Refinery Emissions	11	5,631	7	5,011	89%
Primary Metal Production	20	4,697	11	2,244	48%
Pulp and Paper	15	4,476	13	4,119	92%
Smelting Operations	8	3,555	7	3,397	96%
Miscellaneous	1	2,456	1	2,456	100%
Oil/NG Boilers	5	1,379	5	1,379	100%
Sugar Beet Processing	5	1,150	3	750	65%
Cooling Tower	4	932	4	932	100%
Cement Kilns	4	641	3	524	82%
Turbines	2	838	2	838	100%
Secondary Metal Production	1	537	1	537	100%
Jet Engine Testing	2	535	2	535	100%
Reciprocating Engines	3	525	3	525	100%
Refinery Process Heaters	1	176	1	176	100%
Total	**321**	**114,589**	**262**	**95,308**	**83%**

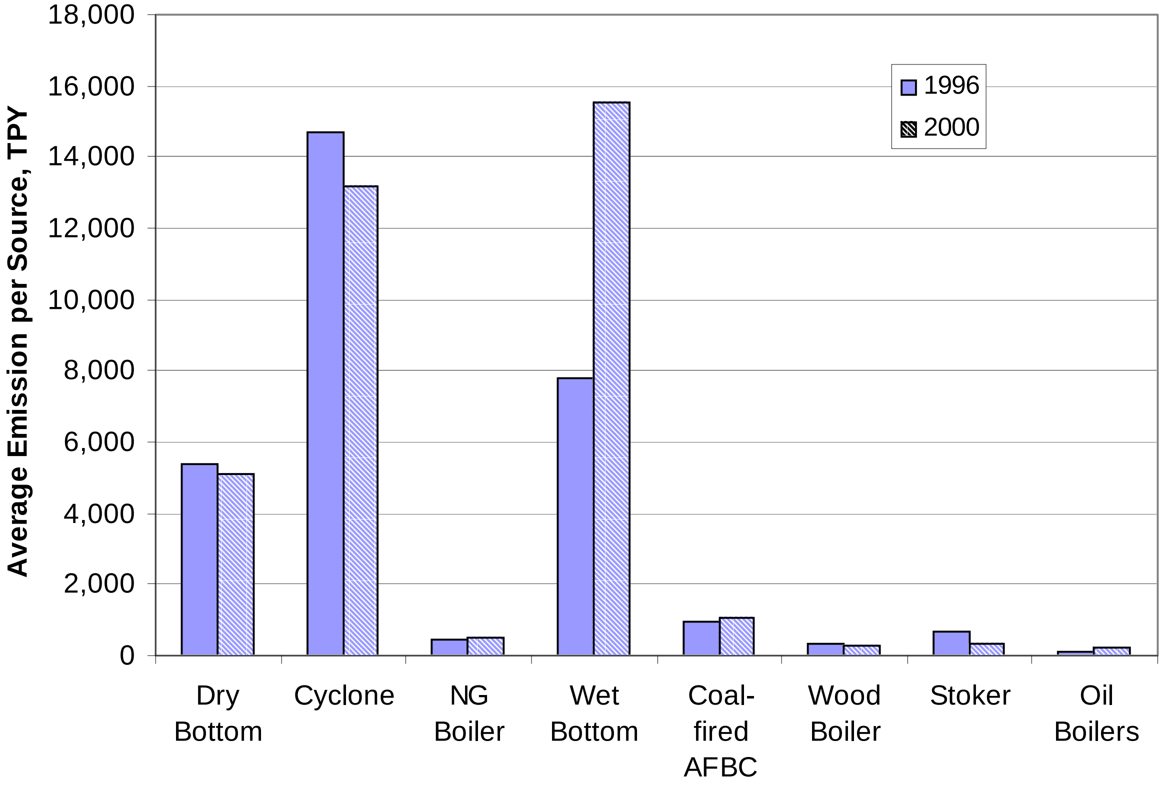

Figure 8. Average Annual NO_x Emissions (greater than 100 TPY) from Electricity Generating Boilers: Comparison of 1996 and 2000 data from EPA Databases.

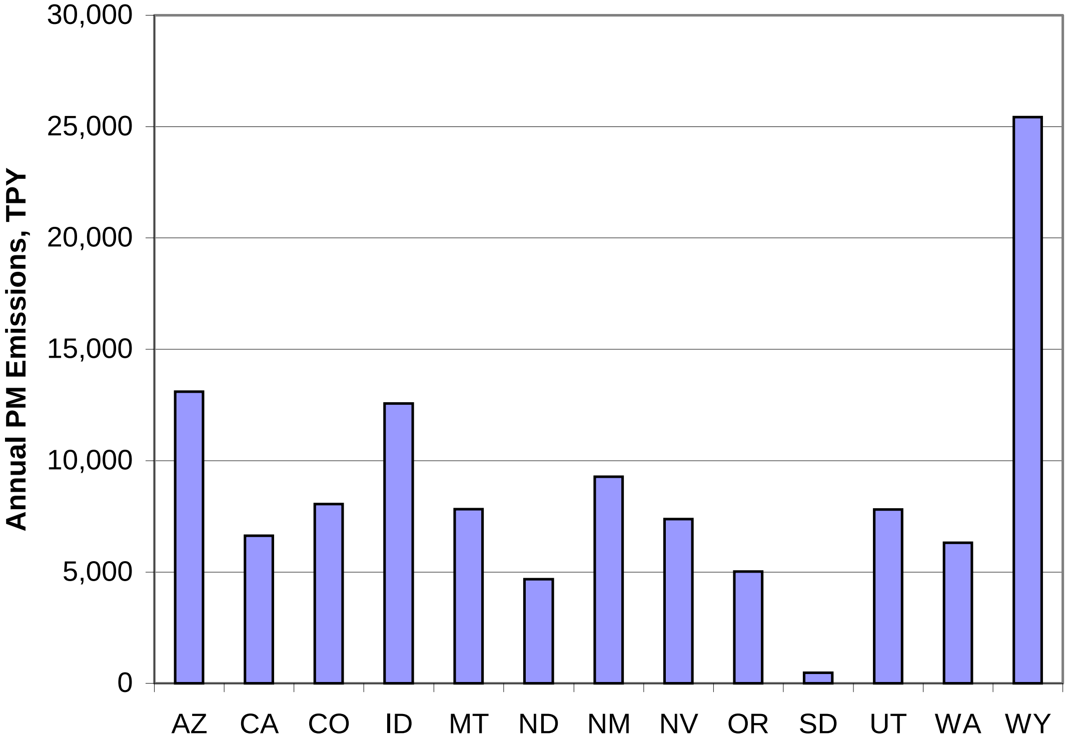

Figure 9. Annual PM Emissions from Sources with Emissions Greater than 100 TPY for the Thirteen-State Region.

Table 9 lists the control technologies in use in the 1996 WRAP database for particulate matter. 72% of coal-fired boilers, the largest category of emissions, had some form of PM control. Overall, though, only 38% of sources with emissions greater than 100 TPY had controls.

Table 9. PM control technologies in use on sources greater than 100 TPY from 1996 WRAP database.

	Number of Units	Controlled Units	Total PM (TPY)	Avg PM (TPY/Source)	PM Control Technology
Coal-Fired Boilers	88	64	46,010	523	Centrifugal Collector (Cyclone)(2), Electrostatic Precipitator(35), Fabric Filter(12), Multiple Cyclone(4), Multiple Cyclone/Electrostatic Precipitator(2), Multiple Cyclone/Wet Scrubber(1), Wet Scrubber(8)
Mineral Processing	85	29	24,499	288	Centrifugal Collector (Cyclone)(2), Dust Suppression by Chemical Stabilizers or Wetting(5), Dust Suppression by Water Sprays(16), Fabric Filter(1), Water Curtain(1), Wet Scrubber(4)
Petrochemical	42	7	10,836	258	Centrifugal Collector (Cyclone)(3), Sulfuric Acid Plant - Contact Process(2), Wet Scrubber(2)
Wood Boilers	24	3	5,718	238	Centrifugal Collector (Cyclone)(1), Wet Scrubber(1)
Refinery Emissions	11	3	5,631	512	Dust Suppression by Water Sprays(2), Fabric Filter(1)
Primary Metal Production	20	7	4,697	235	Alkalized Alumina(2), Dust Suppression by Water Sprays(1), Wet Scrubber(3), Misc.(1)
Pulp and Paper	15	3	4,476	298	Centrifugal Collector (Cyclone)(1), Wet Scrubber(1)
Smelting Operations	8	0	3,555	444	None
Miscellaneous	1	0	2,456	2,456	None
Oil/NG Boilers	5	4	1,379	276	Electrostatic Precipitator(4)
Sugar Beet Processing	5	1	1,150	230	Centrifugal Collector (Cyclone)(1)
Cooling Tower	4	0	932	233	None
Turbines	2	0	838	419	None
Cement Kilns	4	1	641	160	Electrostatic Precipitator(1)
Secondary Metal Production	1	0	537	537	None
Jet Engine Testing	2	0	535	267	None
Reciprocating Engines	3	0	525	175	None
Refinery Process Heaters	1	0	176	176	None
Total	**321**	**122**	**114,590**	**357**	

2.5 Comparison with Other Databases for PM Control Technologies

The 1996 WRAP database was compared with the data available for utility boilers in the 1996 CEMS and E-GRID databases. The EIA-767 database was also searched for PM control technologies. The E-GRID database should contain the information in the other two databases since it contains data from 24 different federal data sources, including EIA data and other EPA data.

EPA and WRAP records for 1996 were matched using ORIS Plant ID numbers and plant names. For matching records, control technologies not listed in the WRAP database were added, capacity (MBtu) entries were added, and PM emissions were replaced from the EPA databases. The EIA-767 database reported PM emissions as lb PM/MBtu, from which we calculated PM emissions in tons per year.

PM emissions data in the EPA databases do not agree with data in the WRAP database, suggesting that the data were obtained from different measurement and/or estimation methods. The differences, illustrated by a few sample records in Table 10, follow no general trend from plant to plant.

Table 10. Sample PM Records from WRAP 1996 and EPA 1996 databases.

Boiler	Capacity (MBtu/yr)	PM Emissions Rate, EPA (PM/MBtu)	PM Emissions Rate, WRAP (PM/MBtu)	PM Emissions, EPA (TPY)	PM Emissions, WRAP (TPY)
Four Corners 1 (NM)	16,530,550	0.03	0.13	248	1,048
Four Corners 2 (NM)	9,369,730	0.03	0.13	141	618
Four Corners 3 (NM)	18,823,220	0.03	0.13	282	1,243
Four Corners 4 (NM)	58,100,720	0.01	0.03	291	883
Four Corners 5 (NM)	52,759,010	0.01	0.03	264	789
Reid Gardner 1 (NV)	9,599,371	0.05	0.05	240	222
Reid Gardner 2 (NV)	23,152,788	0.05	0.01	579	128
Reid Gardner 3 (NV)	30,579,084	0.05	0.02	764	278
Reid Gardner 4 (NV)	42,514,192	0.05	0.01	1,063	245

A comparison of Tables 11 and 12, which contain, respectively, the WRAP data and the WRAP data augmented by the other databases, shows that the combination of the WRAP data and the EPA and EIA data suggests that about 94% of the utility boilers had PM control (in 1996), as compared to only 53% when considering only the WRAP data by itself. The EPA databases probably undergo a more thorough QA/QC procedure than was used to create the WRAP database. Thus, the E-GRID and other federal databases might be expected to have more complete information.

Table 11. PM Emissions and Control Technologies for Utility Boilers in the Thirteen-State Region from WRAP 1996 Database.

	Number of Units	Controlled Units	PM Emissions (TPY)	Average Emissions (TPY/Source)	PM Control Technology
Dry Bottom	60	30	36,889	615	Multiple Cyclone(3), Fabric Filter(8), Wet Scrubber(7), Electrostatic Precipitator(12)
NG Boiler	4	4	1,235	309	Electrostatic Precipitator(4)
Cyclone	3	3	702	234	Electrostatic Precipitator(3)
Stoker	3	0	571	190	None
Coal-fired AFBC	1	1	381	381	Multiple Cyclone(1)
Wet Bottom	1	0	102	102	None
Total	**72**	**38**	**39,880**	**554**	

Table 12. PM Emissions and Control Technologies for Utility Boilers in the Thirteen-State Region from WRAP 1996 Database Combined with EPA and EIA Databases.

	Number of Units	Controlled Units	PM Emissions (TPY)	Average Emissions (TPY/Source)	PM Control Technology
Dry Bottom	77	75	84,140	1,093	Multiple Cyclone(3), Fabric Filter(15), Wet Scrubber(8), Electrostatic Precipitator(44), Multiple Cyclone/Electrostatic Precipitator(3), Multiple Cyclone/Wet Scrubber(2),
Cyclone	5	5	1,633	327	Electrostatic Precipitator(4), Fabric Filter(1)
NG Boiler	4	4	1,235	309	Electrostatic Precipitator(4)
Wet Bottom	3	2	697	232	Fabric Filter(2)
Stoker	3	0	571	190	None
Coal-fired AFBC	2	2	274	137	Multiple Cyclone/Electrostatic Precipitator(1), Fabric Filter(1)
Total	**94**	**88**	**88,549**	**942**	

3 NO_x CONTROL TECHNOLOGIES

3.1 Overview

As discussed in Section 2, the NO_x emissions greater than 100 TPY in the thirteen-state region come predominantly from coal-fired boilers. We have concentrated on obtaining detailed information on NO_x control technologies for the top five categories, which account for 90% of the emission, although in some cases, where information was readily available, we have collected information for other source categories (refinery process heaters, glass melters, and wood-fired boilers). Table 13 shows that these source categories together account for 92% of the NO_x emissions greater than 100 TPY.

Table 13. Annual NO_x emissions greater than 100 TPY from major source categories.

Category	# Units	Total NO_x TPY	% of NO_x Emissions
Coal-Fired Boilers	151	607,748	68%
Reciprocating Engines	423	86,210	10%
Cement Kilns	39	41,009	5%
Oil/NG Boilers	112	32,910	4%
Turbines	86	25,278	3%
Wood Boilers	48	9,776	1%
Refinery Process Heaters	38	9,311	1%
Glass Manufacture	14	5,033	1%
Others	199	69,385	8%
Total	**1,110**	**886,660**	

In this section, the information is organized in two formats. First, Table 14 lists all the technologies considered. For the most part, these are commercial technologies, in that vendors are offering these technologies. Not all technologies listed in Table 14 have demonstrated long-term operation, however. Table 14 gives the following information about each technology:

- Name of the technology
- Source categories to which the technology can be applied
- Was a summary prepared? (Yes/No). If yes, technology summaries are contained in Appendix C.

Second, Tables 15 through 22 summarize the NO_x control options for major source categories for ease of comparison. More detailed information, particularly on the range of cost and NO_x control, is given in Appendix C. These tables contain the following information:

- Name of Technology
- Process Description
- Applicability to units in the source category
- Range of performance (NO_x removal efficiency)
- Range of costs (\$/ton of NO_x removed, levelized annual cost)
- Commercial status

Table 14. NO_x Control Technologies.

	Technology	**Applicability**	**Summary in Appendix C (Y/N)**
1	Air or fuel staging	Coal-fired boilers, Cement kilns	Y
2	Batch/Cullet Preheating	Glass Melters	Y
3	Biosolids injection	Cement kilns	N (not common)
4	Burner Modifications	Coal-fired boilers	N (see LNB)
5	Catalytic combustion	Gas Turbines	Y
6	DLN (fuel-lean combustion)	Gas Turbines	Y
7	Electric Boost	Glass Melters	N (too expensive)
8	Flue Gas Recirculation (FGR)	Oil/Nat'l Gas Boilers	Y
9	Fuel Reburn	Coal-fired boilers, Wood/biomass boilers, Glass Melters	Y
10	High Energy Ignition	Reciprocating Engines	Y
11	High-Pressure Fuel Injection	Reciprocating Engines	Y
12	Hybrid Reburn + SNCR	Coal-fired boilers	N (see Reburn, SNCR)
13	Hybrid SNCR + SCR	Coal-fired boilers	N (see SNCR, SCR)
14	Hydrocarbon-enhanced SNCR	Coal-fired boilers	N (see SNCR)
15	Intelligent controls	Coal-fired boilers, Oil/NG boilers, Wood/biomass boilers	Y
16	Iron addition (CemStar)	Cement kilns	Y

	Technology	Applicability	Summary in Appendix C (Y/N)
17	Kiln dust insufflation	Cement kilns	N (see O_2-enhanced combustion)
18	Kiln temperature control	Cement kilns	Y
19	LNB + FGR	Coal-fired boilers, Oil/NG boilers, Process heaters, Pyrolysis furnaces	N (see LNB, FGR)
20	Low-Emission Combustion (LEC)	Reciprocating Engines	Y
21	Low NO_x Burners	Coal-fired boilers, Oil/NG boilers, Glass Melters, Pyrolysis furnaces, Process heaters, Cement kilns	Y
22	Low-NO_x Calciner	Cement kilns	Y
23	Mid-kiln or tower tire injection	Cement kilns	Y
24	Non-Selective Catalytic Reduction (NSCR)	Reciprocating Engines	Y
25	NOxTech	Reciprocating Engines	Y
26	Overfire Air	Coal-fired boilers, Wood/Biomass boilers. Oil/Nat'l Gas Boilers	Y
27	Oxy-Fuel Firing	Glass Melters	Y
28	Oxygen-enhanced Combustion Modifications	Coal-fired boilers, Cement kilns, Glass Melters	Y
29	Pre-stratified Charge	Reciprocating Engines	Y
30	Rich Reagent Injection (RRI)	Coal-fired boilers	N (see SNCR)
31	SCONOX	Oil/Nat'l Gas Boilers, Reciprocating Engines, Gas Turbines	Y
32	SCR	Coal-fired boilers, Oil/NG boilers, Glass Melters, Pyrolysis furnaces, Process heaters, Reciprocating Engines, Gas Turbines	Y

	Technology	**Applicability**	**Summary in Appendix C (Y/N)**
33	SNCR	Coal-fired boilers, Wood/Biomass boilers Oil/NG boilers, Glass Melters, Pyrolysis furnaces, Cement kilns, Reciprocating Engines, Gas Turbines	Y
34	Tempering (Steam, water or air injection)	Gas turbines, Process heaters, Pyrolysis furnaces	Y

Table 15. Coal-Fired Boilers.

Technology	Description	Applicability	Performance	Cost, $/T	Commercial
Burner Modifications	Burner air and/or fuel modifications to improve air/fuel interaction	Most units.	10 to 30% NO_x reduction	100-200	Y
Fuel Reburn	Inject portion of the fuel into the furnace downstream of burner zone. Usually requires OFA to complete combustion	Most units. Furnace height (residence time) may restrict some applications	20 to 30% NO_x reduction for Fuel-Lean Gas Reburning (no OFA), and 30 to 60% reduction for conventional reburning.	500-2000 (Highly dependent on cost of reburn fuel)	Y
Hybrid Reburn + SNCR	Co-inject reburning fuel and SNCR reagent.	Same as individual technologies.	50-70%	300-600	Y
Hybrid SNCR + SCR	Overfeed reagent into the furnace, and allow ammonia carryover to further reduce NO_x over a catalyst downstream.	Same as individual technologies.	50 to 90% NO_x reduction, de-pending on how much catalyst is installed.	800-2000	Y
Hydrocarbon-enhanced SNCR	Inject small amount of natural gas to create radicals that enhance SNCR effectiveness at 1700 to 2000 °F. Emerging technology.	Most units. Can use more NH_3 with less slip.	40 to 60% NO_x reduction	500-1000	Y
"Intelligent" Controls	Sensors and software optimize air-fuel ratio to burners.	Available for all units	0 to 30% NO_x reduction.	<100-300	Y
Low-NO_x burners (LNB)	Burners designed to produce lower NO_x emissions – "staged" combustion	Most boilers already have LNB.	30-50% NO_x reduction.	200-1000	Y
Overfire air (OFA)	Form of "staged" combustion. Divert portion of the air from the windbox to OFA ports installed above the burners.	Most units. Furnace height may restrict some applications	20 to 40% NO_x reduction.	250-600	Y

Table 15. Coal-Fired Boilers (Continued).

Technology	Description	Applicability	Performance	Cost, $/T	Commercial
Oxygen-enhanced combustion modification	Improve effectiveness of OFA operation by injecting O_2 into fuel-rich flames. Operate more fuel-rich without the problems. Emerging technology.	Best applied with new OFA system designed to achieve stoichiometric air-fuel ratio < 0.8.	30-50% beyond OFA	1000-2000	Y
Rich Reagent Injection (RRI)	SNCR applied to fuel-rich region of OFA system.	Most units. Modeling required to determine injection locations.	20 to 30% additional NO_x reduction beyond OFA.	800-1500	Y
Selective Catalytic Reduction (SCR)	Ammonia added upstream of catalytic reactor installed upstream of air preheater (conventional), downstream of a hot ESP (low dust), or downstream of the cold ESP (tail end).	Most units. Space availability may constrain some options. High sulfur fuels more challenging	70 to 90+% NO_x reduction	1500-2000	Y
Selective Non-catalytic Reduction (SNCR)	Inject ammonia-based reagent into upper furnace (1700-2000 degrees F) to destroy NO_x.	Most. Residence time and temperature characteristics are important.	25 to 50% NO_x reduction, depending on the furnace temperature and time for reaction.	800-1500	Y

Table 16. Reciprocating Engines.

Technology	**Description**	**Applicability**	**Performance**	**Cost, $/T**	**Commercial**
High Energy Ignition	Provide continuous electrical discharge at the spark plug gap for 10 to 90 ^{o} of crankshaft rotation. This extended energy delivery ensures combustion in the leanest of conditions.	For lean-burn engines (to support ignition under very lean conditions)	80% NO_x reduction. Use of plasma ignition is new, so there is limited operating experience.	115-200+	Y
High-Pressure Fuel Injection	Enhance mixing of fuel and air under lean conditions	Same as LEC	~80%	Not available, but less than LEC.	Y
Low-Emission Combustion (LEC)	Retrofit kits available to implement lean burn for new engines as well as retrofit.	Not available for all engines, some fuel efficiency decrease. Requires turbo-charging or inter-cooling upgrades.	80-90% NO_x reduction	190-700, depending on engine BHP. $6500 for 80 BHP.	Y
Non-Selective Catalytic Reduction (NSCR)	Install oxidation-reduction catalyst that uses hydrocarbons in exhaust to destroy NO_x.	Requires rich-burn engine to produce hydrocarbons used for NO_x reduction.	40-98% NO_x reduction, depending on engine speed. Average of 95% reduction is achievable.	<500	Y
NOxTech	Inject chemical reagent into exhaust at temperatures of 1400 to 1500 °F.	Applicable to all engines, but exhaust must be heated for most engines.	90-95% NO_x reduction, 60-80% particulate removal, 50-70% CO removal, 90% hydrocarbon removal.	~ 1000	Y
Pre-stratified Charge	Inject air into intake manifold so that the piston initially draws in air, followed by a fuel-rich air-fuel mixture.	For carbureted, rich-burn engines.	80-95% NO_x reduction.	< 500	Y

Table 16. Reciprocating Engines (Continued).

Technology	Description	Applicability	Performance	Cost, $/T	Commercial
SCONOX	Add chemical reactor for NO_x sorption, followed by regeneration.	Theoretically works for all engines. Catalyst regeneration is difficult. Little operating data available.	95% reduction of NOx, CO, and hydrocarbons.	Not available	Y
SCR	Inject ammonia upstream of a catalyst that operates at 300-900 °F.	All engine types (especially diesel), but difficult to control if load range is wide.	75-90% NOx reduction	< 1000	Y

Table 17. Cement Kilns.

Technology	Description	Applicability	Performance	Cost, $/T	Commercial
Air or fuel staging	Inject portion of the fuel downstream of the main flame to create locally reducing conditions where NO_x can be destroyed. Sometimes includes installing a "NO_x fan" to increase burnout.	More easily implemented in tower kilns.	0 to 50% NO_x reduction, depending on existing equipment.	1000-2000	Y
Biosolids injection	Add sewerage sludge to mid-kiln or tower for combined SNCR and fuel-staging affect.	Tried in long kilns and preheater/precalciner kilns, but effectiveness is limited by poor combustion and increased hydrocarbon or SO_2 emissions.	20 to 30% NO_x reduction, but can reduce kiln capacity due to high moisture content.	100-500	Y
Iron addition (CemStar)	Change cement formulation by adding waste iron to lower clinkering temperature and suppress NO_x.	Applicable to all kiln types, but may affect cement quality.	20 to 30% NO_x reduction, depending on cement specifications	0-100	Y
Kiln dust insufflation	Re-inject cement kiln dust (CKD) into flame zone to lower peak temperatures and increase clinker production.	Applicable to long kilns.	0 to 20% NO_x reduction in conjunction with a 0-5% kiln capacity increase.	100-300	Y
Kiln temperature control	Add temperature-monitoring device to kiln controls to minimize high-temperature excursions where more NO_x is emitted.	Applicable to all kiln types, but risks unacceptable cement quality.	0 to 20% NO_x reduction, and requires less operator attention.	200-500	Y
Low-NO_x Burner (LNB)	Replace open pipe burner with multi-annular design. Usually accompanied by installation of an indirect coal feed system to reduce coal transport airflow.	Applicable to all kiln types. Can reduce cement quality on some kilns.	0 to 20% NO_x reduction; production may increase.	500-1000	Y

Table 17. Cement Kilns (Continued).

Technology	**Description**	**Applicability**	**Performance**	**Cost, $/T**	**Commercial**
Low-NO_x calciners	Replace calciner with new low-NO_x design.	Applicable only to preheater/precalciner kilns.	30-50% NO_x. Little experience	1000-5000	Y
Mid-kiln or tower tire injection	Inject whole tires or shredded tires downstream of the flame to reduce NO_x formed in the burner.	Injected mid-kiln in long kilns, and into lower tower for preheater/precalciner kilns.	15 to 30% NO_x reduction; generate revenues.	0-1000	Y
Oxygen enrichment	O_2 lance to decrease fuel requirement for clinker formation.	Cement quality could be more difficult to control.	0 to 20% NO_x reduction and potential for additional capacity.	200-1000	Y
SNCR	Inject ammonia-based reagent into upper furnace (1700-2000^{o}F) to destroy NO_x.	Applicable to preheater/precalciner kilns.	30 to 70% NO_x reductions, depending on access to temperatures in 1600-1800 °F range.	200-1000	Y

Table 18. Oil/Natural Gas-Fired Boilers.

Technology	Description	Applicability	Performance	Cost, $/T	Commercial
Flue Gas Recirculation (FGR)	Recycle 15-25% of the flue gas to the windbox to reduce flame temperature. Can use eductors for induced FGR	Most units, but could affect heat balance. Induced FGR requires pressure part changes.	40-80% NO_x reduction	500-3000	Y
Low-NO_x Burners	Burners designed to produce lower NO_x emissions – “staged” combustion	Most boilers.	30-60% NO_x reduction	200-1000	Y
Overfire Air (OFA)	Form of “staged” combustion. Divert portion of the air from the windbox to OFA ports installed above	Most units. Furnace height may restrict some applications	40-80% NO_x reduction	1000-2000	Y
SCONOX	Add chemical reactor for NO_x sorption, followed by regeneration.	Steam-hydrogen regeneration gas not practical for some boilers. Limited testing to date.	70-99% NO_x reduction claimed.	Not available	Y
SCR	Ammonia added upstream of catalytic reactor.	Most units. Space availability may constrain some options. High sulfur fuels more challenging	70-90+% NO_x reduction	2000-10000	Y
SNCR	Inject ammonia-based reagent into upper furnace (1700-2000°F) to destroy NO_x.	Most. Residence time and temperature characteristics are important.	30-60% NO_x reduction	1300-3000	Y

Table 19. Turbines.

Technology	Description	Applicability	Performance	Cost,$/T	Commercial
Catalytic combustion	Catalytic combustor reduces combustion temperature below thermal NO_x limit.	Limited experience.	0.05 lb/MBtu (80% reduction) has been measured.	> 500	Y
DLN (fuel-lean combustion)	Low NO_x combustor is GT "equivalent" of LNB.	Most turbines. Flame instability a problem for some gas fuels.	0.1 lb/MBtu (70% reduction) can be guaranteed on new units.	1000-2000	Y
SCONOX	Add chemical reactor for NO_x sorption, followed by regeneration.	Reliability of system not yet proven.	0.02 lb/MBtu (> 90% reduction) claimed.	> 7000	Y
SCR	Add catalyst section to HRSG to destroy NO_x at temperatures of 600 to 900 °F.	Applied to most turbines	90 % reduction down to 0.03 lb/MBtu.	500-10000+	Y
Tempering (Water/ Steam Injection)	Spray water or steam into combustor to suppress flame temperature.	Can be applied to most turbines, but some will experience slight efficiency loss.	0.15 lb./MBtu (50% reduction) can be achieved.	2000-7000	Y

Table 20. Wood or Biomass-Fired Boilers.

Technology	**Description**	**Applicability**	**Performance**	**Cost, $/T**	**Commercial**
Fuel Reburn	Inject portion of the fuel into the furnace downstream of burner zone. Usually requires OFA to complete combustion	Stoker, water tube	40-60% NO_x reduction	300-3000	Y
"Intelligent" Controls	Sensors and software optimize air-fuel ratio to burners.	Watertube boilers	0-20 % NO_x reduction	200-500	Y
Overfire air (OFA)	Form of “staged” combustion. Divert portion of the air from the windbox to OFA ports installed above the burners.	Stoker, watertube	20-60% NO_x reduction	200-2000	Y
Selective Non-Catalytic Reduction (SNCR)	Inject ammonia-based reagent into upper furnace (1700-2000^o F) to destroy NO_x.	Stoker, FBC, watertube	40-80 % NO_x reduction reported	900-2200	Y

Table 21. Process Heaters.

Technology	Description	Applicability	Performance	Cost, $/Ton	Commercial
LNB + FGR	Staged firing with flue gas mixed with pre-combustion air	Oil/gas fired, MD only	50-60%	Gas: 1,720-2,480 Oil: 2,390-2,910	Y
Low-NO_x Burners, Ultra Low-NO_x Burners	Staged firing; Combines staged firing with induced flue gas recirculation	Oil/gas fired	30-50% Ultra-LNB: 50-80%	Gas: 1,210-1,820 Oil: 1,200-2,340 Gas: 810-1,280 Oil: 400-1,440	Y
SCR	Ammonia added upstream of catalytic reactor.	Oil/gas fired	75-90%	Gas: 5,130-10,600 Oil: 3,710-6,490	Y
SNCR	Inject ammonia-based reagent into upper furnace (1700-2000^o F) to destroy NO_x.	Oil/gas fired	50-70%	Gas: 1,470-2,640 Oil: 1,230-2,350	Y

Table 22. Glass Melting Furnaces.

Technology	Description	Applicability	Performance	Cost, $/Ton	Commercial
Batch/Cullet Preheating	Residual heat of waste gas used to preheat batch materials/cullet (recycled glass)	Any glass melting furnace w/ >50% cullet in batch	5-25%	890-1,040	Y
Electric Boost			10-30%	2,600-9,900	Y
Low-NO_x Burners	Burners designed to produce lower NO_x emissions – “staged”		40%	790-1,680	Y
Natural Gas Reburn	Inject portion of the fuel into the furnace downstream of burner zone.		50-65%	moderate	Y
Oxy-Fuel Firing	Oxygen used instead of air; requires different furnace design	Oil/gas fired furnaces	80-85%	2,150-4,400	Y

The formation of NO_x is a byproduct of the combustion of fossil fuels. Nitrogen contained in fuels such as coal and oil, as well as the harmless nitrogen in the air, will react with oxygen during combustion to form nitrogen oxides (NO_x). The degree to which this formation evolves is dependent on many factors, including both the combustion process itself and the properties of the particular fuel being burned. This explains why similar boilers firing different fuels or similar fuels burned in different boilers will yield different NO_x emissions.

As a result of these complex interactions in the formation of NO_x, an equally large number of approaches to minimize or reduce its emissions into the atmosphere have been and continue to be developed. A relatively simple way of understanding the many technologies available for NO_x emission control is to divide them into two major categories: (1) those that minimize the formation of NO_x during the combustion process (e.g., smaller quantities of NO_x are formed); and (2) those that reduce NO_x after the combustion process. It is common to refer to the first approach as “combustion modifications” whereas technologies in the second category are termed "post-combustion controls."

Within each of these categories, several technologies and variations of the same technology exist. Finally, combinations of some of these technologies are not only possible but often desirable as they may produce more effective NO_x control than the application of a stand-alone technology.

The following summaries describe the major technologies in each category.

3.2 Coal-Fired Boilers

Combustion modifications can vary from simple "tuning" or optimization efforts (similar to a "tune-up" of a car) to the deployment of dedicated technologies such as low-NO_x burners (LNB), Overfire air (OFA), or Reburn. All combustion modification approaches face a common challenge: that of striking a balance between NO_x reduction and fuel efficiency. The concern is exemplified by the typically higher carbon levels in the fly ash, which reflect lower efficiency (more fuel needed for the same electrical output) and which may contaminate the fly ash itself, possibly making it unsuitable for reutilization (e.g., cement and concrete production).

Combustion Optimization

Combustion optimization efforts can lead to reductions in NO_x emissions of 5%-15% or even higher in cases where a unit may be poorly "tuned." It is important to remember that optimization results are truly a function of the "pre-optimization" condition of the power plant or unit, and as such have limited opportunity for drastic emission reductions. Recent development of "intelligent controls" - software-based systems that "learn" to operate a unit and then maintain its performance during normal operation may go a long way towards keeping plants well-tuned as they age.

LNB’s and OFA

LNB’s and OFA represent practical approaches to minimizing the formation of NO_x during combustion. Simply, this is accomplished by controlling the quantities and the way in which fuel and air are introduced and mixed in the boiler (usually referred to as "fuel or air staging"). These technologies are the most prevalent in the power industry at present. For example, plants that have had to comply with Phase I of Title IV of the CAAA of 1990 have largely used these technologies for compliance. (Phase II of the Title IV has required the use of post-combustion technologies to meet more stringent requirements for both Group 1 and Group 2 boilers.) Competing manufacturers have proprietary designs, geared towards application in different boiler types, as well as reflecting their own design philosophies. LNB's and OFA, which can be used separately or as a system, are capable of NO_x reductions of 40% - 60% from uncontrolled levels. Again, the type of boiler (e.g., dry vs. wet-bottom, wall- vs. tangential-fired, NSPS vs. pre-NSPS) and the type of fuel (e.g., bituminous vs. sub-bituminous) will influence the actual performance achieved. NO_x emission rates on the order of 0.15 lb/MBtu can be achieved with low NO_x burners under circumstances, particularly in dry-bottom boilers burning low-rank coals.

LNB's/OFA have little or no impact on operating costs, other than those noted above. As such, the economics of these technologies are driven by capital/retrofit costs which typically range from \$10-\$40/kW, with the lower range reflecting easier "plug-in" application, whereas the higher costs are typically associated with more difficult and involved retrofits (e.g., where new controls or other systems may be replaced as part of the LNB retrofit).

From the standpoint of scheduling retrofits for existing units, LNB/OFA retrofit projects have "lead" times of 10-14 weeks and can require outages of 6-10 weeks, depending on factors such as scope of work, integration with other plant outage requirements, etc.

Reburn

Reburn, while generically included in the "Combustion Modification" category, is different from the other technologies in this group (LNBs/OFA) in that it "destroys" NO_x through chemically reducing conditions shortly after it is formed rather than minimizing its formation as discussed previously. From a practical standpoint, this is accomplished by introducing the reburn fuel (theoretically any fossil fuel can be used, but natural gas is the most common) into the boiler above the main burner region. Subsequently, this "fuel-rich" environment reacts with and "destroys" the NO_x formed in the main burners. This technology has been implemented in the U.S. and overseas, and while not as common as LNB/OFA, it is commercial at this time. Owing to stricter compatibility criteria, reburn is not as universal as LNB/OFA in its applicability to the overall boiler population. Specific criteria such as boiler size, availability of natural gas, type and quality of the main fuel are all important in determining the suitability of a unit for this technology. One important feature of reburn is its compatibility with cyclone boilers, for which the previously mentioned technologies are not particularly well suited. Cyclones boilers represent over 25,000 MW of capacity in the U.S.

Reburn performance has been shown to range from 35%-60% depending on such factors as reburn fuel type and quantity, initial NO_x level, boiler design, etc. Reburn can be thought of as a "dial-in" NO_x technology in that NO_x reductions are a function of the amount of reburn fuel. This feature may provide strategic value in compliance scenarios.

With respect to cost, systems using natural gas as the reburn fuel range from $15/kW to $30/kW whereas those using coal for reburn range from $30/kW to $60/kW. Operating costs are primarily driven by the fuel cost differential in the case of gas reburn, while for coal or oil reburn fuel preparation costs (pulverization and atomization, respectively) represent the dominating O&M costs. Countering these costs, particularly in the gas reburn case, are SO_2, particulates, and CO_2 co-benefits proportional to the fraction of gas used.

Project retrofit schedules for this technology are on the order of 15 to 20 weeks with 6 to 10 weeks of outage time likely.

Recently, reburn technology has evolved into several variations of the original approach. One of these is "Fuel Lean Gas Reburn" (FLGR) developed for specific applications where NO_x reductions of around 30%-40% may be required. FLGR uses less gas than conventional reburn (3%-7% vs 15%-20%), and its capital cost is less than $10/kW, making it a potentially effective option in specific applications.

SCR and SNCR

Readily available post-combustion NO_x controls are limited to selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). They are fundamentally similar in that both use an ammonia-containing reagent to react with the NO_x produced in the boiler and convert it to nitrogen and water. SNCR accomplishes this at higher temperatures (1700ºF-2000ºF) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 600ºF) and hence needs a catalyst to produce the desired reaction between ammonia and NO_x.

While this difference between the two technologies may seem minor, it results in significant difference in performance and costs. This is because in the case of SNCR, the reaction occurs in a somewhat uncontrolled fashion (e.g., the existing upper furnace becomes the "makeshift" reactor, which is not what it was originally designed to be), while in the SCR case, a dedicated reactor and the reaction-promoting catalyst ensure a highly controlled, efficient reaction. In practice, this means that SNCR has lower capital costs (no need for a reactor/catalyst); higher operating costs (lower efficiency means that more reagent is needed to accomplish a given reduction in NO_x); and finally, has limited NO_x reduction capability (typically 30%-40%, with some cases achieving reductions in the 50% range). SCR, on the other hand, has higher capital costs but offers lower operating costs and the opportunity for very high NO_x reductions (up to 90%).

Capital costs range from $10 to $15/kW and $60 to $100/kW for SNCR and SCR, respectively. Operating costs are driven primarily by the consumption of the chemical reagent – usually urea for SNCR and ammonia for SCR, which in turn is dependent upon the efficiency of the process (usually referred to in terms of reagent utilization) as well as the initial NO_x level and the desired percent reduction. Two additional parameters important in the overall operating costs are (1) the potential contamination of fly ash by ammonia, making it unusable and (2) the life cycle of the catalyst due to fly ash.

Combined Approaches

In theory, most of these technologies can be used together. However, NO_x reductions are not necessarily additive, and more importantly, the “economics” of the combined technologies may or may not be cost-effective. Such analyses are highly site- and strategy-specific.

However, several such combinations of technology are considered attractive and have or are gaining acceptance. For example, the combination of LNB/OFA with either SCR or SNCR is more prevalent than the application of the post-combustion technologies alone. The economics of this approach are justified by the reduced chemical (SNCR) and capital costs (SCR – smaller reactor/catalyst) due to lower NO_x levels entering the SCR/SNCR system. Another example is the combination of Reburn with SNCR, driven by the synergisms between the two (similar location, temperatures in the boiler). This application may yield NO_x reductions of 60%-70% with capital costs in the \$20-\$30/kW range, but has a relatively high operating cost due to reagent and reburning fuel consumption.

3.3 Reciprocating Engines

Several control technologies are available for ICE’s, having a wide range of complexity, cost and performance.

Some in-cylinder methods offer low to moderate NO_x reductions at costs well below \$1,000/ton. These include injection timing retard, and air/fuel ratio adjustment (with or without high-energy ignition). These methods are widely available, and NO_x performance will vary from one engine design to another. However, fuel efficiency can suffer as a result of these methods and emissions of products of incomplete combustion can increase.

Spark-ignited engines that can be retrofitted with Low-Emission Combustion (LEC) technology can potentially achieve significant NO_x reductions (80 to 90%). LEC technology can be expensive to retrofit on some engines, and it may not be available from all engine manufacturers. For large, low-speed engines, LEC technology is estimated to provide annual NO_x reductions of about 80% at under \$1,000/ton under most conditions. LEC technology is estimated to be more cost effective on smaller, medium-speed engines (under \$500/ton for annual control under most conditions). It is estimated to be somewhat more expensive for dual-fuel engines (annual control at a capacity factor of 65% is estimated to cost under \$1,000/ton).

SCR is the only commercially available choice for post-combustion control of diesel and lean-burn spark-ignition engines. Experience in the U.S. with SCR on these engines is growing, especially for diesel engines. SCR has been applied to approximately 30 diesel engines and to an equivalent number of constant-load lean burn ICE’s. Experience with SCR on variable-load engines is limited. In analysis using data from case studies, it was estimated that SCR provides annual NO_x reductions of as high as 90% at a cost below \$1,000/ton in all cases, except for very low capacity factors (~10%), and it provides seasonal reductions at a cost of under \$1,000/ton for engines operating at high capacity factors (typically, 65% or greater).

Recent developments from the application of urea-SCR on mobile sources (diesel trucks) offer the possibility of reducing the size and capital cost of SCR systems for stationary ICE’s. This new technology, developed from efforts to apply SCR to mobile diesel engines, appears to make it possible to achieve much more cost-effective NO_x reduction on stationary ICE's that operate for only a few hundreds of hours a year. NO_x reduction of about 75% is estimated to be possible for under $2,000/ton even for seasonal controls of some stationary ICE's that operate only a few hundred hours each ozone season. Seasonal control at a cost of under $1,000/ton is estimated to be achievable for most applications with capacity factor greater than 45%.

3.4 Cement Kilns

As with other combustion systems, modifying the combustion process is one strategy for reducing NO_x in cement kilns. However, the quality of the clinker produced by the kiln can be affected by combustion modifications so these must be undertaken carefully.

Monitoring temperature and excess air in the combustion zone increases the efficiency of the cement-making process and can result in reduced NO_x emissions. Combustion modifications include staged combustion of air or fuel. Specifically designed low-NO_x burners are sometimes used. Even without low-NO_x burners, staging can be achieved by adding some of the fuel mid-kiln, as in mid-kiln injection of tires. Mid-kiln injection of fuel (most often tires) was in practice in twenty kilns in the U.S. in 2000.

Iron addition (CemStar process) has been used at about a dozen facilities in the U.S. This reduces the temperature needed in the kiln for formation of clinker and allows the combustion zone to operate cooler (and thus reducing NO_x).

Post-combustion (post-kiln) NO_x controls include SCR and SNCR. SCR has not been used on cement kilns in the U.S.; pilot studies have been conducted in Europe. SNCR technology requires a specific temperature window and residence time; these are not attainable in all cement kilns. SNCR can be applied to preheater/precalciner kilns. SNCR is widely practiced in Europe on cement kilns, but to date there have been only a handful of demonstrations in the U.S.

3.5 Natural Gas and Oil Fired Boilers

The menu of NO_x control options for gas and oil-fired boilers is essentially the same as for coal-fired boilers. One noted exception is the use of Flue Gas Recirculation (FGR), which is not effective in coal applications and hence, is not mentioned there.

While the control technologies are common to the coal-fired options, application issues require different considerations and analyses. Examples range from differences in the inherent NO_x formation amongst the fuels (thermal NO_x vs. "fuel"-NO_x), which dictate that combustion-based technologies are designed accordingly for each fuel, to the fact that gas produces no PM or SO_2/SO_3 and hence can afford some design changes from coal and oil applications. Equally important are the economics of the different fuels, which may favor different technology approaches.

In summary it can be said that the available menu of technologies is the same as for coal applications, but that (at least for gas), deployment of these technologies tends to be less constraining than for coal.

3.6 Turbines

There have been some important developments in gas turbine NO_x control technology, but well-established technologies continue to play an important role in reduction of NO_x. Dry Low NO_x (DLN), catalytic combustion, and some new post-combustion methods are making their way into the control technology market, while water or steam injection and SCR continue to be important technologies for reducing NO_x from gas turbines.

Many turbine manufacturers can convert or replace conventional combustors on existing turbines with DLN combustors. DLN combustion retrofits have been made possible by recent developments in gas turbine combustor technology. DLN technology offers the potential for substantial reduction of NO_x from turbines firing natural gas or other low-nitrogen fuels, as well as improved engine performance when compared to wet controls (water or steam injection). For turbines under about 15 MW in size, NO_x emissions of 25 ppm can be guaranteed for new turbines and emissions below 42 ppm can be guaranteed for retrofitted turbines. For large turbines (75 MW and higher in size), controlled NO_x emission levels of as low as 9 ppm have been guaranteed, even for retrofits.

DLN capital costs vary with the size of the turbine and the specifics of the particular turbine being retrofitted. The baseline NO_x level significantly affects the estimate of cost per ton of NO_x reduced. Using expected baseline NO_x emissions levels provided by the turbine manufacturers and retrofit costs expected to be typical of most applications, retrofit of DLN on industrial turbines (about 3 to 10 MW) originally equipped with conventional combustion control is estimated to provide NO_x reductions under $2,000/ton for annual controls with high capacity factors and at a higher cost for seasonal controls. For larger turbines (~75 MW), cost was estimated to be well below $1,000/ton for nearly all conditions.

Water injection and steam injection are two well-established technologies that can offer controlled NO_x emission levels below 42 ppm in many cases. Because water or steam injection technologies frequently have lower capital cost than DLN but higher variable costs, these technologies can be more attractive for peaking turbines or other turbines that operate infrequently. It was estimated that water injection installed on peaking units that operate 200 hours to 400 hours in the summer would reduce NO_x at a cost of about $2,500/ton to about $7,000/ton, depending upon the number of operating hours and the fuel used (gas or distillate oil).

SCR continues to be the most widely used post-combustion technology for gas turbines. Catalyst technology developments have made SCR viable over a wider temperature range. This makes SCR a viable control option in situations that were difficult in the past, such as simple-cycle turbines that may now benefit from high-temperature SCR and combined-cycle turbines with duct burners that may now benefit from low-temperature SCR.

The cost of NO_x reduction with SCR varies considerably according to application, turbine size, and the type of SCR technology that is appropriate for the application. As in the case of the DLN cost estimates, expected baseline NO_x emissions levels provided by the turbine manufacturers were used as a basis for cost calculations. Conventional SCR on a large (~75MW) combined-cycle turbine with high capacity factors was estimated to cost about

\$440/ton for annual controls and \$870/ton for seasonal controls, for turbines equipped with conventional combustion technology (baseline NO_x emissions of 154 ppm). For turbines with lower baseline NO_x emissions (such as those equipped with DLN combustors having baseline NO_x emissions of 15 ppm), the cost per ton of additional NO_x removed was estimated to be greater, ranging from about \$3,700/ton (annual control, high capacity factor) to over \$13,000/ton (seasonal controls, low capacity factor). On smaller turbines (~5 MW), the cost of conventional SCR is estimated to be as low as \$1,300/ton (with annual control and conventional combustion technology having baseline NO_x emissions of 142 ppm). Seasonal controls for smaller turbines are estimated at over \$15,000/ton of NO_x removed at a low capacity factor (45%) with baseline NO_x emissions of 42 ppm.

For installations that may be better suited for high- or low-temperature SCR variants, such as simple-cycle turbines (high-temperature SCR) or combined-cycle turbines with limited space (low-temperature SCR), the cost of SCR is somewhat higher than for conventional SCR on a combined-cycle plant. A 75 MW turbine at a high capacity factor equipped with conventional combustion technology (baseline NO_x emissions of 154 ppm) can be controlled annually with high- or low-temperature SCR for about \$550/ton and for about \$1,200/ton seasonally. As with conventional SCR, turbines with lower baseline NO_x emissions (such as those equipped with DLN combustors) showed a higher cost per ton of NO_x reduction. The estimated cost of NO_x reduction for a 75 MW turbine with baseline NO_x emissions of 15 ppm ranges from \$5,170/ton (annual controls, high capacity factor of 85%) to as high as \$20,000/ton (seasonal controls, low capacity factor of 45%). On smaller turbines (~5MW), the cost for high- or low-temperature SCR is estimated to be as low as \$2,000/ton with annual control and conventional combustion technology (baseline NO_x emissions of 142 ppm). Cost is estimated to range from \$6,750/ton (annual controls, high capacity factor of 85%) to about \$27,000/ton (seasonal controls, low capacity factor of 45%) with baseline NO_x emissions of 42 ppm.

Emerging combustion technologies (such as catalytic combustion) and post-combustion technologies (such as SCONOx) offer the potential for very low NO_x emission levels. Because there is much less experience with these technologies, available cost information is limited.

4 PM CONTROL TECHNOLOGIES

4.1 Overview

As discussed in Section 2, 8 source categories make up about 92% of the PM emissions and are summarized in Table 23. Detailed information on PM control technologies has been obtained for industrial processes that generate particulate matter. We have not provided cost information on fugitive emissions, however, since costs of fugitive dust control are highly variable and it is difficult to find an adequate metric for costs and then quantify them.

Table 23. PM emissions from top eight source categories.

	# Units	**Total PM TPY**	**% PM Emissions**
Coal-Fired Boilers	88	46,010	40%
Mineral Processing	85	24,499	21%
Petrochemical	42	10,836	9%
Wood Boilers	24	5,718	5%
Refinery Emissions	11	5,631	5%
Primary Metal Production	20	4,697	4%
Pulp and Paper	15	4,476	4%
Smelting Operations	8	3,555	3%
Others	28	9,168	8%
Total (>100 TPY)	**321**	**114,589**	

Table 24 lists all the technologies considered. These are commercial technologies, in that vendors are offering these technologies with demonstrated operating experience in a wide range of applications. Table 24 gives the following information about each technology:

- Name
- Source categories to which the technology can be applied
- Summary prepared? (Y/N)

Technology summaries are contained in Appendix D.

Table 24. PM Control Technologies

	Technology	Applicability	Summary (Y/N)
1	Cyclones	Coal-fired boilers, Oil/NG boilers, Wood/Biomass boilers, Cement kilns, Smelting	Y
2	Electrostatic precipitator (ESP)	Coal-fired boilers, Oil/NG boilers, Wood/Biomass boilers, Cement kilns	Y
3	Fabric Filter	Coal-fired boilers, Oil/NG boilers, Wood/Biomass boilers, Cement kilns	Y
4	PM Scrubber	Coal-fired boilers, Oil/NG boilers, Wood/Biomass boilers, Cement kilns, smelting	Y
5	Surface modification • Water • Surfactants • Shape	Fugitive Emissions, Mineral Products	N
6	Traffic operations	Fugitive Emissions, Mineral Products	N

4.2 PM Control for Coal-Fired Boilers and Other Combustion Sources

Particulate matter is generated by a variety of physical and chemical processes. It is emitted to the atmosphere through combustion, industrial processes, fugitive emissions and natural sources. In combustion processes, the mineral matter (inorganic impurities) is converted to ash. The particles suspended in the flue gas are known as fly ash. Fly ash constitutes the primary particulate matter, which enters the particulate control device. Particulate matter is in general referred to as "PM", "PM10", "PM2.5" (particulate matter (PM) with an aerodynamic equivalent diameter of 10 microns or less and 2.5 microns or less, respectively).

Quantity and characteristics of the fly ash and particle size distribution depend on the mineral matter content of the fuel, combustion system, and operating conditions. Combustion technique mainly determines the particle size distribution in the fly ash and hence the final particulate emissions. Common combustion systems in pulverized coal firing include dry bottom, wall (front, opposed) and corner (tangential) burners and wet bottom furnaces. In dry bottom boilers, 10-20% of the ash is discharged as dry, bottom ash. In wet bottom boilers, 50-60% of the ash is discharged at the bottom of the boiler as slag. Stokers or grate-fired boilers are used to burn coal, wood and waste. The majority of the ash falls through the grate and is discharged as bottom ash. Mineral composition of the coal and the amount of carbon in the fly ash determine the quantity, resistivity and cohesivity of the fly ash.

PM emissions from other point source processes involve similar phenomena where particulate matter is carried with the flue gas, in suspension to the stack. Hence, the general technologies applicable to one source are typically suitable for the others as well. Factors such as type and quantity of PM, characteristics of the process gas (temperature, moisture, other contaminants) will have a major influence on the selection and design of the PM control technology.

Without getting into the details of the various technologies, the following four major types of particulate controls technologies are common for a variety of applications:

- Wet scrubbers – scrubbers work on the principle of rapid mixing and impingement of the particulate with the liquid droplets and subsequent removal with the liquid waste. For particulate controls the “venturi scrubber” is an effective technology whose performance is directly related to the pressure loss across the venturi section of the scrubber. Venturi scrubbers are effective devices for particulate control. However, for higher collecting efficiencies and a wider range of particulate sizes, higher pressures are required. High-energy scrubbers refer to designs operating at pressure losses of 50-70 inches of water. Of course, higher pressure translates to higher energy consumption. Performance of scrubbers varies significantly across particle size range with as little as 50% capture for small (<2 microns) sizes to 99% for larger (>5 microns) sizes.

- Electrostatic Precipitators (ESP) –ESP’s operate on the principle of electrophoresis, by imparting a charge to the particulates and collecting them on opposed charged plates. Dry vs. wet refers to whether the gas is water cooled and saturated prior to entering the charged plate area, or is collected dry on the plates. In gases with high moisture content, dry ESP’s are not suitable because the wet gas would severely limit the ability to collect the “sticky” particulates from the plates. The wet ESP technology is capable of very high removal efficiencies and is well-suited for the wet gas environments. Both types of ESP’s are capable of 99+% removals for particle sizes above 1 micron.

- Fabric Filters – These are essentially “giant” vacuum cleaners. As in the case of the dry ESP, Fabric Filters are not well suited for wet gas applications. However FFs are extremely efficient in collecting PM including fine (submicron) size fractions.

- Cyclones – Cyclones are devices that separate particulates from the gas stream through aerodynamic/centrifugal forces. However, the technology is only effective in removing larger size particulates (greater than about five microns).

4.3 Other Developments

While the technologies above represent the major available options for particulate control from point sources, it is relevant to note that advancements and innovative application of these technologies have and will continue to occur. Examples of these can vary from simple retrofits (e.g. new filter bag materials for Fabric Filters or newer spark control electronics on ESPs) to innovations including electrostatically- enhanced fabric filtration and hybrid concepts that combine attributes of various technologies.

The Electric Power Research Institute’s (EPRI) COHPAC process and the University of North Dakota Energy and Environmental Research Center’s Advanced Hybrid Particulate Collector

(AHPC) are examples of hybrid particulate collectors. In COHPAC, an ESP is followed by a pulse-jet Fabric Filter either immediately following it or actually integrated into the original casing of the ESP (in the case of larger older ESP's), where the FF acts as a "polishing" device significantly increasing the overall and fine particulate collection efficiency of the ESP alone. The AHPC technology can be described as an ESP with alternating rows of electrode plates and highly efficient membrane filter bags. In this case, the technology benefits from good synergism between the ESP and FF during bag cleaning resulting in very high performance levels, small sizes and operational flexibility.

4.4 Costs

As with most control technologies, the costs of PM controls involve both capital and operating costs. A cost-effectiveness indicator such as $/ton as is typically used for other technologies (e.g. NO_x and SO_2) is very difficult to address for generic PM control costs, as the range of PM reductions for different fuels and processes is wide that cost ranges become useless. An attempt to summarize costs in terms of capital and O&M components is presented below.

Capital

While it is customary to indicate capital costs on a $/kW basis for power generation applications, this is not relevant for non-power applications since no electricity is generated. However, one of the main parameters dictating the "sizing" and hence, the costs of a PM control device, is the quantity of flue gas it must handle. As a result, it is more appropriate to generalize capital costs on a "$/ACFM" basis. The following values represent typical costs for several of these technologies (these numbers reflect unit sizes ranging from utility-size units up to about 2,000,000 ACFM to smaller process down to about 10,000 ACFM))

- Dry ESPs - $15 - $40/ACFM
- Wet ESPs - $15 - $40/ACFM
- Reverse Air Fabric Filter - $17 - $40/ACFM
- Pulse Jet Fabric Filter - $12 - $40/ACFM
- Venturi Scrubber - $5 - $20/ACFM
- Cyclone - $1 - $5/ACFM

O&M

O&M costs are difficult to generalize for such a variety of technologies and applications, as they are affected by many parameters that include type of fuel, type of process, local ash disposal options, local cost of power, etc. O&M costs include fixed costs (FOM) and variable costs (VOM). The costs provided below are presented in $/year-ACFM and reflect costs for coal based fuels but should reasonably apply to other sources as well.

Fixed O&M

- Dry ESPs - $0.25 - $0.65/yr-ACFM
- Wet ESPs - $0.15- $0.50/yr-ACFM
- Reverse Air Fabric Filter - $0.35 - $0.75/yr-ACFM

- Pulse Jet Fabric Filter - $0.50 - $0.90/yr-ACFM
- Venturi Scrubber - $0.25 - $0.65/yr-ACFM
- Cyclone – Not applicable

Variable O&M

- Dry ESPs - $0.45 - $0.60/yr-ACFM
- Wet ESPs - $0.25 - $0.50/yr-ACFM
- Reverse Air Fabric Filter - $0.70 - $0.80/yr-ACFM
- Pulse Jet Fabric Filter - $.90 - $1.1/yr-ACFM
- Venturi Scrubber - $1.2 - $1.8/yr-ACFM
- Cyclone – Not applicable

5 MULTI-POLLUTANT CONTROL TECHNOLOGIES

Emerging environmental issues and proposed federal legislation (President's Clear Skies Initiative, Carper Bill, Jeffords' Bill) as well as state legislation (examples include MA, NY, NC, NH, CT) have driven interest in multi-pollutant (as opposed to single pollutant) control technologies capable of addressing air pollutant emissions more comprehensively with greater flexibility and ultimately lower cost. Multi-pollutant control technologies integrate in-situ and/or post-combustion controls of at least two of the following pollutants: SO_2, NO_x, and Hg (and other hazardous air pollutants including cadmium, arsenic, and nickel), and CO_2. Multi-pollutant controls are intended primarily for large utility coal-fired boilers since the complexity of some of these processes as well as regulatory drivers often limit them to larger, utility boilers. Since coal-fired boilers represent the single largest source category for both NO_x (as well as SO_2 and Hg) and PM in the thirteen-state region, it is worth considering some of these technologies.

5.1 Proposed Multi-pollutant Emission Regulations from Utility Boilers

In 2002 and 2003 three "multi-pollutant" bills were introduced in the US Congress that call for coordinated reductions in NO_x, SO_2, and Hg from coal-fired power plants [26]. Some of the bills also include emission limits for CO_2. The three bills are briefly summarized here.

- The Clean Power Act (CPA, Jeffords) would amend the CAA to require electric power generation sources greater than 15 MW. It is the most stringent of the three proposals. It will cap SO_2 emissions at 2.26 mm TPY in 2008 (0.28 mm TPY in the western region that includes WRAP states and MT, WY and CA; and 1.98 mm TPY in the eastern region). For NO_x, the cap of 1.51 mm TPY is to be met by 2008. The cap on Hg is at 5 TPY, also to be met by 2008. In addition, this bill sets a cap of 2.08 billion TPY for CO_2 to be met by 2008 (roughly 1990 levels). Except for Hg, national trading will be allowed to meet the caps.

- The Clear Skies Act (CSA) has been proposed by the Bush administration. It is the least stringent of the three proposals. It would cap SO_2 emissions at 4.5 mm TPY in 2010 and at 3 mm TPY in 2018. The corresponding limits for NO_x are 3 mm TPY (in 2008) and 1.7 mm TPY in 2018. For Hg, the proposed national caps are at 26 TPY in 2010 and 15 TPY in 2018. There are no limits for CO_2. A national trading program similar to the existing trading program for SO_2 emissions under Title IV of the Clean Air Act will be the implementation mechanism to achieve these caps. All electric generation sources greater than 25 MW would fall under this program.

- The Clean Air Planning Act (CAPA, Carper,Breaux, Baucus, and Chafe)) was intended as middle ground between the CPA and CSA. For SO_2, the caps are 4.5 mm TPY by 2008, 3.5 mm TPY by 2012, and 2.25 mm TPY by 2015. The caps for NO_x are 1.87 mm TPY by 2008 and 1.7 mm TPY by 2012. The Hg cap limits are 24 TPY by 2008, and a potential cap of 5-16 TPY by 2012 (this cap to be set by EPA and implies a control in the range of 79 to 93% from current Hg emission level). Cap and trade program will be the implementation mechanism for all four pollutants, except trading for Hg will be limited. In a "hybrid" approach, limited trading for Hg would be allowed (each plant will be required to reduce its Hg emissions at site by at least 50% in 2008 and by 75% in 2012). For CO_2, CAPA proposes to stabilize CO_2 emissions at 2005 levels (approximately 2.6 billion TPY) by 2008, and then stabilize to 2001 levels (approximately 2.4 billion TPY) by 2012.

All three bills recognize and incorporate the WRAP SO_2 trading program by setting separate caps on SO_2 emissions in the West. The CPA and CAPA allow nationwide trading of NO_x, while the CSA divides the country into two zones for NO_x trading. The western zone includes the ND, SD, NE, OK, KS, western TX, the eleven states west of the Rockies, AK, HI and the U.S. territories. The largest differences among the three bills are in the Hg emissions reduction requirements. The first-phase Hg emissions caps under CSA and CAPA are about the same, but compliance would come two years earlier under CAPA. CPA has the most stringent Hg reduction requirement: a cap of 5 TPY or about 90% control. The CSA would allow nationwide Hg trading, while the CAPA would allow partial trading. There is no trading under CPA.

Both CSA and the first phase of CAPA have modest Hg emission reduction targets; these would make it possible in some cases to achieve reduction of Hg as a “co-benefit” of other control technologies, for example, from the combination of an SCR and wet scrubber. If one of these bills were enacted, there might be some additional incentive to install an SCR and/or FGD on plants for which there might not be justification on the basis of a single pollutant.

In terms of Hg co-benefits, the West is at a disadvantage as compared to the East. In the latter region, more utilities burn bituminous coals that are high in chlorine (which tends to increase the amount of oxidized Hg in flue gas) and in sulfur. Wet scrubbers are effective for the removal of oxidized Hg, but ineffective for removal of the elemental Hg that is the predominant form of Hg in many western power plants. If all coal-fired power plants must reduce Hg emissions by upwards of 70%, the West will have a more difficult job than the East, owing to differences in coal composition. The bills that allow Hg trading (CSA and CAPA) would allow western power plants to deploy Hg control technology at plants were the highest emissions reductions are likely to be achieved.

If the CPA is enacted or if none of the three bills are enacted this year, it is likely that EPA will continue with the MACT process for Hg control, which does not allow trading and which will probably impose a Hg emission reduction target in the range of 70% to 90% (or an emission limit in the range of 0.2 to 0.6 pound of Hg per trillion Btu input). In this case, coal-fired power plants will have to look at application of activated carbon injection, the most mature technology for Hg control currently, or one of the multi-pollutant processes under development. Activated carbon injection may require adding additional particulate control equipment (such as a polishing baghouse with high cloth to air ratio), which will lower PM as well as the emissions of other hazardous pollutants including arsenic, chromium, lead, manganese, and nickel) as a consequence.

5.2 Multi-pollutant Control Technologies

A multi-pollutant control technology may be one integrated process or a combination of synergistic processes. In addition to in-situ and post-combustion control processes, options such as advanced power generation technologies, power plant rehabilitation-upgrading-repowering, fuel switching or blending and power plant optimization are sometimes included in the multi-pollutant control category. Emerging and commercial processes for multi-pollutant control for coal-fired boilers are summarized in Table 25, which is largely taken from Reference 4, with more recent information from the DOE-EPRI-U.S. EPA -A&WMA Combined Power Plant Air Pollutant Control Symposium in Washington, D.C., May 19-22, 2003.

Approximately half of the options listed in Table 25 are in commercial and early commercial stages. However, nearly all the options in commercial stage are proven SO_2 control technologies, which also remove Hg, advanced power generation options and power plant upgrading-fuel switching options. Nearly all in-situ and post-combustion controls (SO_2-NO_x or SO_2-NO_x-Hg) are either in demonstration or pilot-scale. Some technologies (e.g., SNO_X, SNRB, Advacate and CZD) have been tested either in pilot or demonstration scale in the early phase of the U.S. Department of Energy's Clean Coal Technology (CCT) program, but have not been adopted by the industry. Some of these technologies may become more cost-effective if additional controls are required. Most of the environmental control processes increase the auxiliary power requirements of the plant (some up to 5%, but mostly in the range of 1 to 2%), increasing proportionally the CO_2 emissions.

Emerging post-combustion, multi-pollutant control technologies are being developed by a number of companies. The Electro-Catalytic Oxidation (ECO) system is a four-stage pollution control process that integrates established technologies to remove SO_2, NO_x, Hg and PM2.5. The system also produces a valuable fertilizer byproduct. The AIRborne process removes SO_2 and NO_x from plant emissions while turning the leftover material into a high-quality granular fertilizer. EnviroScrub is a dry scrubbing system that results in control of SO_2, NO_x, and possibly mercury and results in a byproduct that can be sold into the fertilizer, chemical, and/or explosives industry. None of these technologies controls emissions of CO_2.

Capital costs of options controlling two pollutants (either SO_2-NO_x or SO_2-Hg) are projected to be in the 50-315 $/kW range, but there is significant uncertainty associated with these estimates because of their early stage of development. Also, lack of information, especially associated with O&M costs, makes it difficult to compare their cost-effectiveness. Further monitoring and updating of cost-related information is needed. For reference, the costs of the combined commercial technologies, FGD and SCR are above 200-250 $/kW.

Advanced power generation technologies such as circulating fluidized bed (CFB), pressurized fluidized bed (PFBC) and integrated gasification combined cycle (IGCC) are potentially attractive options because they are revenue-generating options, while reducing significantly SO_2 and NO_x, and to a lesser extent CO_2. These options are available mainly for new power plants. Also, supercritical pulverized coal boiler provides an attractive alternative to subcritical pulverized coal boiler for nearly the same investment and results in an additional 4-12% reduction of all emissions. While this may not seem to be a significant percentage, their cost-effectiveness is attractive; also, the amount of CO_2 reduction (in tons or tons per year) is significant.

Of particular interest are options such as power plant optimization, fuel blending or switching and power plant upgrading. These options may play an important role in a flexible compliance regulatory framework and may result in significant savings for the utility industry compared to the implementation of control technology options. Optimization involves only operating changes, and while it results in only minor emission reductions, its costs are very low and therefore it is an attractive option and should be pursued in all power plants. Fuel blending or switching, and power plant upgrading provide significant opportunities for emission control, but their site-specific nature makes it difficult to generalize regarding their emission reduction potential and cost-effectiveness. A more site-specific assessment is recommended to assess the potential for these options in a typical utility system.

Table 25. Commercial and Emerging Multi-Pollutant Control Technologies for External Combustion Boilers.

Technology	**Status**	**Emissions Reductions**	**Applicability**	**Issues**
SO_2/Mercury Control				
Dry Scrubbers (conventional)	C	SO_2: >95%; NO_x: NA; Hg: 5-85%	Low to medium sulfur coals	Hg removal can vary significantly with coal type, operating conditions
SO_2 sorbents, low temperature	P/C	SO_2: 40-85%; NO_x: NA; Hg: 0-90%	Units with ESP or FF for particulate control	Potential impacts on ESP or FF
SO_2 sorbents, furnace injection	C/D	SO_2: 65-70%; NO_x: NA; Hg: 65-90%	Existing plants, especially older units less than 300 MW	Demonstration on long-term basis needed
Activated carbon with SO_2 sorbent processes	P/C	SO_2: 40-85%; NO_x: NA; Hg: 50-90%	Units with ESP or FF for particulate control	Not used commercially, potential impacts on ESP or FF
Wet FGD with mercury oxidation processes	P	SO_2: 95%; NO_x: NA; Hg: 80+%	Wet Scrubber Plants	Full scale demonstration underway, insufficient information at present
Wet FGD with wet ESP	C/P	SO_2: 99%; NO_x: NA; Hg: 80+%	Integration with wet scrubbers, retrofit dry ESPs, new units	Few application in power industry, potentially expensive alloys required
Advanced Dry FGD	P/C	SO_2: 90-98%; NO_x: NA; Hg: <90%	NOX-Hg control for low to medium sulfur coals(same as Spray Dryers)	Hg removal may vary significantly with coal type, operating conditions (similar to Spray Dryers)
SO_2/NO_x Control				
E-BEAM	C/D	SO_2: 95+%; NO_x: 50-90%; Hg: NA	New and retrofit	High costs and auxiliary power requirements
SNOX	C	SO_2: 90+%; NO_x: 50-90%; Hg: 0%	New and retrofit	Cost-effectiveness
SNRB	P	SO_2: 80-90%; NO_x: 50-90%; Hg: 0%	New and retrofit	Requires demonstration
AIRborne	D	SO_2: 90->99%; NO_x: 50-60%; Hg: 30-75%	New and retrofit	Demonstration in progress; capital cost comparable to FGD-SCR
Thermal NOX	D	SO_2: 90-95%; NO_x: 80-90%; Hg: NA	New and retrofit	In demonstration

Status: P = pilot stage; C = commercial; D = demonstration

Table 25. Commercial and Emerging Multi-Pollutant Control Technologies for External Combustion Boilers. [Continued]

Technology	**Status**	**Emissions Reductions**	**Applicability**	**Issues**
SO_2/NO_x/Mercury Control				
Activated Coke	C	SO_2: 90-98%; NO_x: 60-80%; Hg: 90-99%	New and retrofit	High costs, especially operating costs due to high activated coke costs
Activated carbon with particulate controls	P/C	Hg: 50-90%	Retrofit and new units with ESP an/or FF	Not widely demonstrated at full scale, ash salability, ESP/FF performance, impact of mercury speciation
Electro Catalytic Oxidation	D	SO_2: 95-98%; NO_x: 90%; Hg: 70+%	New and Retrofit	Demonstration required
EnviroScrub	D	SO_2: 99+%; NO_x: 99%; Hg: 60-70%	New and retrofit.	Demonstration required; costs estimated to be 30-50% lower than FGD-SCR
Wet FGD and SCR	C	SO_2: 95%; NO_x: 90-95%; Hg: 0-80%	Plants with SCR and Wet scrubber technologies	Depends on Hg speciation in flue gas.

Status: P = pilot stage; C = commercial; D = demonstration

6 SUMMARY AND RECOMMENDATIONS

6.1 NO_x and PM Sources

The main objectives of this project were to identify and briefly describe the available (or emerging) technologies for control of NO_x and PM emissions that could be applied to sources in the western United States. The starting point for this work was an analysis of large (greater than 100 TPY) sources from the WRAP 1996 Emission Inventory (Version 3). Sources were limited to those from the thirteen-state region: AZ, CA, CO, ID, MT, ND, NM, NV, OR, SD, UT, WA, and WY.

The source profile from the thirteen-state region was compared with that from the nine-state GCVTR: AZ, CA, CO, ID, NM, NV, OR, UT, and WY. The GCVTR accounted for 75% of the NO_x emissions and 83% of the PM emissions within the thirteen-state region. Generally, the distribution of sources was the same in the GCVTR as compared to the thirteen-state region. Thus, conclusions based on the thirteen-state region should therefore be valid for the GCVTR while achieving broader applicability to WRAP members.

The cut-off of 100 TPY captures 84% of the NO_x emissions in the 1996 WRAP database for the thirteen-state region. For ICE's (reciprocating engines and turbines) the 100 TPY cut-off only captures about 56% of the emissions, though this category is the second largest category and responsible for 10% of stationary source emissions. Thus, NO_x control programs for sources in this category will require careful consideration of population attributes (e.g., a large number of small sources).

The largest source category for NO_x by far in the thirteen-state region is coal-fired boilers (68%); the top five categories (coal-fired boilers, internal combustion engines, cement kilns, turbines and oil and natural gas boilers) account for 90% of the NO_x emissions. The states with the largest stationary source NO_x emissions according to the 1996 WRAP database were AZ, CA, ND, NM, UT, and WY.

According to the WRAP 1996 (Version 3) stationary source emissions database, about 4% of the NO_x sources greater than 100 TPY had at least one type of control. Coal-fired boilers had the highest level of control (15%), followed by petrochemical processes (13%). The level of control for coal-fired boilers seemed low, even for 1996. Therefore, the 1996 WRAP database was compared with the data available for utility boilers in the 1996 CEMS and E-GRID databases. The EIA-767 database was also searched for NO_x control technologies. This comparison only looked at coal-fired utility boilers and not all coal-fired boilers. However, only 3% of the WRAP NO_x emissions from coal-fired boilers in the thirteen-state region were from non-utility boilers. WRAP data augmented by these other databases suggested that 44% of the utility boilers had at least one type of NO_x control in 1996, mostly low-NO_x burners.

The NO_x emission rate from external combustion boilers that is achievable with combustion modification depends on the fuel type. For coal-fired boilers, lower NO_x emission rates are obtained when firing subbituminous coal as compared to bituminous coal. Considering the amount of subbituminous coal in the West, there is a fairly even split between bituminous and subbituminous coals as fuels for utility boilers. This may have shifted since 1996, however.

The cut-off of 100 TPY captures 60% of the PM emissions in the 1996 WRAP database for the thirteen-state region. The largest source category in the thirteen-state region is coal-fired boilers (40%); the top eight categories account for 92% of the PM emissions (greater than 100 TPY): coal-fired boilers, mineral processing, petrochemical, wood boilers, fugitive, primary metal production, pulp and paper, and smelting operations. The state with the largest PM emissions is WY, followed by AZ, ID, and NM.

In the 1996 WRAP database, 72% of coal-fired boilers, the largest category of emissions, had PM controls. Overall, though, only 38% of units had PM controls.

6.2 Controls for NO_x and PM

Many commercially available technologies exist for control of NO_x and PM emissions from stationary sources. Twenty-five NO_x control technologies and four PM control technologies were summarized. Cost and performance information was obtained for most technologies.

There are a lot more technologies available for NO_x control because of the different ways in which NO_x can be prevented or destroyed. In contrast, PM control on industrial processes is often done only at the back end of the process. This is not to say that process modification cannot be used to reduce PM emissions. Fugitive emissions, for example, can sometimes be controlled by process modification. Further work should be done to look into the details of important industrial processes to determine where process modification will yield significant reductions in PM.

Most of the NO_x emissions from stationary sources are generated by combustion or by high temperature thermal processing. NO_x control technologies fall broadly into two categories: combustion modifications and post-combustion removal or destruction. Combustion systems differ, from internal combustion engines to external combustion boilers. Thus, there are many different strategies for modifying the combustion process. Deciding on an appropriate NO_x control technology is highly dependent on the process conditions and on the type of fuel. The existing NO_x control technology on a particular source will also influence what additional NO_x controls can be added successfully. Post-combustion NO_x controls are not truly “back-end” technologies, like ESPs and baghouses for PM control; some degree of process integration is required. Thus, not all post-combustion control processes can be applied to a given source.

There is no “one size fits all” solution for NO_x control. Deciding which technology to apply to a certain source depends on:

- The fuel type;
- The specific combustion process;
- Post-combustion characteristics: temperature, residence times, etc.;
- The type of NO_x control technology already in use; and
- The target NO_x emission rate.

Emerging environmental issues and regulatory changes have driven interest in multi-pollutant (as opposed to single pollutant) control technologies capable of addressing air pollutant emissions more comprehensively with greater flexibility and ultimately lower cost. Multi-pollutant control technologies integrate in-situ and/or post-combustion controls of at least two of the following: SO_2, NO_x, and mercury pollutants, and CO_2 emissions. Multi-pollutant controls are intended primarily for external combustion boilers, particularly coal-fired boilers. The complexity of some of these processes as well as regulatory drivers often limit them to larger, power-generation boilers.

Emerging post-combustion, multi-pollutant control technologies are being developed for SO_2, NO_x, and mercury that could be applied to stationary combustion sources in the western U.S. in the next five or ten years. These processes generally produce a saleable byproduct and have SO_2 removal rates of greater than 50%, and NO_x removal rates of greater than 70%. Several of these processes are currently in pilot or full-scale demonstration. Costs of options controlling two pollutants (either SO_2-NO_x or SO_2-Hg) are projected to be in the 50-315 $/kW range, but there is significant uncertainty associated with these estimates because of their early stage of development. Also, lack of information, especially associated with O&M costs, makes it difficult to compare their cost-effectiveness. Further monitoring and updating of cost-related information is needed. For reference, the costs of the combined commercial technologies, FGD and SCR are above 200-250 $/kW.

6.3 What's on the horizon? What trends will influence emissions and control technologies?

- The rate of advancement and use of multi-pollutant technologies (NO_x/Hg, SO_2/Hg, PM/Hg, etc.) will depend on the levels of future mercury emissions reduction.
- Significant enhancements have been made in the ability of combustion modifications to reduce NO_x formation, but they may be reaching their maximum potential given the theoretical limits within the combustion process and given the nitrogen content of some fuels (e.g., coal). Determining how much NO_x emissions can be reduced in the West through this type of technology will require closer examination of the types and vintages of combustion modifications already in place.
- There is (and always will be) uncertainty in the future mix of fuels for some combustion processes (e.g. electricity production). This influences the retirement of existing sources and the investment in new sources, which, in turn requires that a range of projections be made for future source distribution scenarios.
- Historically new technologies have had one major evaluation criteria in common: their performance improvement over the existing technology (e.g. SCR capable of 90% reductions over SNCR). As technologies push the potential control levels to 90% or more, we need to view them from a new perspective, one which includes greater emphasis on overall impacts, costs, inter-pollutant compatibility, etc.

6.4 Recommendations for Future Work

Further work must be done in order to generate both accurate costs and reasonable control scenarios to be used in both regional-scale atmospheric models and in evaluating regional control strategies, particularly in light of the multi-pollutant control legislation currently under consideration in Congress. This includes the following:

- Accurate cost information (generally available now);
- Details of the emission-generating processes;
- NO_x and PM control technologies already in place; and
- Accurate estimates of the current emissions.

Better use could be made of existing EPA databases; in addition, the WRAP database should be updated to give a more accurate description of sources and existing control technology.

In this work, we found that the EPA databases (CEMs and E-GRID) were easy to use and provided what appeared to be a fairly complete picture of current emissions and control technologies for NO_x and PM. Since much has changed in the West since the 1996 WRAP stationary source inventory, these databases are useful for getting more current information on utility boilers, which generate a significant amount of the emissions in the western U.S. It would be worthwhile now to look at trends in emissions and NO_x control technologies in the West by analyzing the most recent CEMs and E-GRID databases.

Sufficient detail about the configuration and process of the sources is generally not available in the EPA databases and these databases are only for utility boilers. The next WRAP inventory should be used to collect the information needed to make estimates of costs for control. Better identification of sources is important; there are instances in the 1996 WRAP database in which there is insufficient information on the type of source and/or the fuel in use. Obviously, better identification of existing air pollution control technology is critical. For combustion sources, particularly utility boilers, the capacity, in terms of MBtu/yr should also be included in the WRAP database.

Consideration should also be given to selecting a subset of sources for detailed characterization and calculate ranges of costs and expected emissions reductions. The subset should be a representative distribution of those sources within the most important source categories.

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APPENDIX A : Breakdown of NO_x Emissions by State

Table A-1. WRAP NO_x Emissions for sources > 100 TPY by State

Category	**13-States**		**AZ***		**CA***		**CO***	
	# Units	**Total NO_x TPY (>100 TPY)**	**# Units**	**Total NO_x TPY (>100 TPY)**	**# Units**	**Total NO_x TPY (>100 TPY)**	**# Units**	**Total NO_x TPY (>100 TPY)**
Coal-Fired Boilers	151	607,748	15	75,018	3	1,544	31	82,927
Reciprocating Engines	423	86,210	16	6,441	58	10,274	56	11,328
NG	*404*	*81,786*	*14*	*5,731*	*54*	*9,436*	*56*	*11,328*
Diesel	*16*	*4,021*	*2*	*709*	*3*	*708*		
Process Gas	*3*	*403*			*1*	*130*		
Cement Kilns	39	41,009	2	4,662	16	15,886	4	4,470
Oil/NG Boilers	112	32,910	4	1,092	40	12,290	9	2,643
Turbines	86	25,278	8	1,918	37	8,990	9	1,655
NG	*83*	*24,821*	*7*	*1,795*	*37*	*8,990*	*9*	*1,655*
Diesel	*3*	*457*	*1*	*123*				
Mineral Processing	34	16,250	4	2,861	4	3,263		
Petrochemical	48	13,719	1	101	13	3,978	4	730
NG Compressor	16	10,959	14	10,686				
Pulp and Paper	39	10,010			3	602		
Wood Boilers	48	9,776			14	2,430		
Refinery Process Heaters	38	9,311			28	7,096		
Glass Manufacture	14	5,033			11	4,128	1	251
Primary Metal Production	17	3,476	2	1,009			2	244
Waste Combustion	6	3,309						
Refinery Emissions	8	3,256			8	3,256		
In-process Fuel Use	9	2,605			7	1,906		
Jet Engine Testing	4	2,297			4	2,297		
Oil and Gas Production	7	1,140						
Smelting Operations	3	961	2	852				
Sugar Beet Production	3	730			1	111		
Secondary Metal Production	4	507						
Turbines, Steam	1	165			1	165		
Total (> 100 TPY)	1,110	886,659	68	104,639	248	78,217	116	104,249

*** GCTVR State**

Table A-1. WRAP NO_x Emissions for sources > 100 TPY by State [continued]

Category	**ID***		**MT**		**ND**		**NM***	
	# Units	**Total NO_x TPY (>100 TPY)**	**# Units**	**Total NO_x TPY (>100 TPY)**	**# Units**	**Total NO_x TPY (>100 TPY)**	**# Units**	**Total NO_x TPY (>100 TPY)**
Coal-Fired Boilers	6	2,218	6	25,452	17	108,007	10	70,193
Reciprocating Engines			14	4,357	8	2,569	201	37,755
NG			*4*	*2,056*	*8*	*2,569*	*201*	*37,755*
Diesel			*10*	*2,301*				
Process Gas								
Cement Kilns			1	1,662			1	1,000
Oil/NG Boilers			1	128	3	909	10	3,389
Turbines	1	139	0	0	3	564	12	2,947
NG	*1*	*139*			*3*	*564*	*12*	*2,947*
Diesel								
Mineral Processing	1	117	3	428			1	145
Petrochemical	3	1,449	5	842	1	915	1	124
NG Compressor								
Pulp and Paper	3	377	4	920				
Wood Boilers	4	708	4	1,057			1	360
Refinery Process Heaters							1	206
Glass Manufacture								
Primary Metal Production								
Waste Combustion					4	2,971		
Refinery Emissions								
In-process Fuel Use			1	589				
Jet Engine Testing								
Oil and Gas Production					2	348	1	140
Smelting Operations								
Sugar Beet Production					2	619		
Secondary Metal Production								
Turbines, Steam								
Total (> 100 TPY)	18	5,008	39	35,436	40	116,901	239	116,258

*** GCTVR State**

Table A-1. WRAP NO_x Emissions for sources > 100 TPY by State [continued]

Category	**NV***		**OR***		**SD**		**UT***	
	# Units	**Total NO_x TPY (>100 TPY)**	**# Units**	**Total NO_x TPY (>100 TPY)**	**# Units**	**Total NO_x TPY (>100 TPY)**	**# Units**	**Total NO_x TPY (>100 TPY)**
Coal-Fired Boilers	8	39,040	1	4,195	3	17,268	15	66,600
Reciprocating Engines							15	2,074
NG							*14*	*1,772*
Diesel							*1*	*303*
Process Gas								
Cement Kilns	2	3,789	2	687	3	2,718	2	565
Oil/NG Boilers	6	3,727	6	2,155			1	267
Turbines	1	191	3	5,372	2	435	3	772
NG			*2*	*5,229*	*2*	*435*	*3*	*772*
Diesel	*1*	*191*	*1*	*143*				
Mineral Processing	2	218			2	577	5	4,542
Petrochemical							2	324
NG Compressor							2	273
Pulp and Paper			14	3,641				
Wood Boilers			17	3,366				
Refinery Process Heaters								
Glass Manufacture								
Primary Metal Production	1	125	3	514			7	1,263
Waste Combustion							2	339
Refinery Emissions								
In-process Fuel Use	1	109						
Jet Engine Testing								
Oil and Gas Production								
Smelting Operations								
Sugar Beet Production								
Secondary Metal Production								
Turbines, Steam								
Total (> 100 TPY)	21	47,199	46	19,929	10	20,998	54	77,020

*** GCTVR State**

Table A-1. WRAP NO_x Emissions for sources > 100 TPY by State [continued]

Category	**WA**		**WY***	
	# Units	**Total NOx TPY (>100 TPY)**	**# Units**	**Total NOx TPY (>100 TPY)**
Coal-Fired Boilers	8	20,138	28	95,148
Reciprocating Engines	7	1,191	48	10,219
NG	*5*	*918*	*48*	*10,219*
Diesel				
Process Gas	*2*	*273*		
Cement Kilns	4	4,126	2	1,444
Oil/NG Boilers	28	5,758	4	553
Turbines	3	324	4	1,971
NG	*3*	*324*	*4*	*1,971*
Diesel				
Mineral Processing	4	1,904	8	2,197
Petrochemical	11	3,635	7	1,619
NG Compressor				
Pulp and Paper	15	4,471		
Wood Boilers	8	1,856		
Refinery Process Heaters	9	2,009		
Glass Manufacture	2	654		
Primary Metal Production	1	116	1	205
Waste Combustion				
Refinery Emissions				
In-process Fuel Use				
Jet Engine Testing				
Oil and Gas Production			4	652
Smelting Operations	1	109		
Sugar Beet Production				
Secondary Metal Production	4	507		
Turbines, Steam				
Total (> 100 TPY)	105	46,798	106	114,009

***GCVTR State**

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APPENDIX B : Breakdown of PM Emissions by State

Table B-1. WRAP PM Emissions for sources > 100 TPY by State

Category	**13-States**		**AZ***		**CA***		**CO***	
	# Units	**Total PM TPY**	**# Units**	**Total PM TPY**	**# Units**	**Total PM TPY**	**# Units**	**Total PM TPY**
Coal-Fired Boilers	88	46,010	9	2,657	1	699	3	684
Mineral Processing	85	24,499	14	4,932	5	710	18	4,700
Petrochemical	42	10,836			5	834	4	757
Wood Boilers	24	5,718			3	471		
Refinery Emissions	11	5,631	2	3,949	1	104	3	843
Primary Metal Production	20	4,697	3	529	1	139	1	232
Pulp and Paper	15	4,476			2	272		
Smelting Operations	8	3,555	1	137				
Miscellaneous	1	2,456			1	2,456		
Oil/NG Boilers	5	1,379						
Sugar Beet Processing	5	1,150	1	210	1	110	1	430
Cooling Tower	4	932						
Cement Kilns	4	641			1	132		
Turbines	2	838	1	590			1	248
Diesel	1	590	1	590				
NG	1	248					1	248
Secondary Metal Production	1	537						
Jet Engine Testing	2	535			2	535		
Reciprocating Engines	3	525	1	104			1	169
Diesel	2	273	1	104			1	169
NG	1	252						
Refinery Process Heaters	1	176			1	176		
Total	**321**	**114,589**	**32**	**13,107**	**24**	**6,638**	**32**	**8,063**

*** GCTVR State**

Table B-1. WRAP PM Emissions for sources > 100 TPY by State [continued]

Category	**ID***		**MT**		**ND**		**NM***	
	# Units	**Total PM TPY**	**# Units**	**Total PM TPY**	**# Units**	**Total PM TPY**	**# Units**	**Total PM TPY**
Coal-Fired Boilers	8	5,180	4	3,990	11	3,679	9	7,285
Mineral Processing	5	1,864	9	2,565	1	110	2	270
Petrochemical	4	688	2	274	1	590	1	307
Wood Boilers	6	1,683	2	242				
Refinery Emissions								
Primary Metal Production			1	477				
Pulp and Paper	6	2,949						
Smelting Operations			1	158			4	1,242
Miscellaneous								
Oil/NG Boilers								
Sugar Beet Processing					1	297		
Cooling Tower								
Cement Kilns	1	216	1	117			1	176
Turbines Diesel NG								
Secondary Metal Production								
Jet Engine Testing								
Reciprocating Engines Diesel NG								
Refinery Process Heaters								
Total	**30**	**12,579**	**20**	**7,825**	**14**	**4,676**	**17**	**9,280**

*** GCTVR State**

Table B-1. WRAP PM Emissions for sources > 100 TPY by State [continued]

Category	**NV***		**OR***		**SD**		**UT***	
	# Units	**Total PM TPY**	**# Units**	**Total PM TPY**	**# Units**	**Total PM TPY**	**# Units**	**Total PM TPY**
Coal-Fired Boilers	8	5,688	1	108	2	236	8	2,436
Mineral Processing	2	244					11	2,510
Petrochemical								
Wood Boilers			11	3,056				
Refinery Emissions					1	233		
Primary Metal Production	1	211	1	276			4	857
Pulp and Paper			5	898				
Smelting Operations							2	2,017
Miscellaneous								
Oil/NG Boilers	4	1,235	1	144				
Sugar Beet Processing								
Cooling Tower								
Cement Kilns								
Turbines Diesel NG								
Secondary Metal Production			1	537				
Jet Engine Testing								
Reciprocating Engines Diesel NG								
Refinery Process Heaters								
Total	**15**	**7,379**	**20**	**5,019**	**3**	**469**	**25**	**7,820**

*** GCTVR State**

Table B-1. WRAP NO_x Emissions for sources > 100 TPY by State [continued]

Category	**WA**		**WY***	
	# Units	**Total PM TPY**	**# Units**	**Total PM TPY**
Coal-Fired Boilers	4	2,968	20	10,400
Mineral Processing			18	6,594
Petrochemical	2	255	23	7,130
Wood Boilers	2	266		
Refinery Emissions	3	386	1	115
Primary Metal Production	8	1,976		
Pulp and Paper	2	357		
Smelting Operations				
Miscellaneous				
Oil/NG Boilers				
Sugar Beet Processing	1	103		
Cooling Tower			4	932
Cement Kilns				
Turbines				
Diesel				
NG				
Secondary Metal Production				
Jet Engine Testing				
Reciprocating Engines			1	252
Diesel				
NG			1	252
Refinery Process Heaters				
Total	**22**	**6,311**	**67**	**25,423**

***GCVTR State**

APPENDIC C: NO_x Control Technology Summaries

Process: Air or Fuel Staging

Category	NO_x, TPY (WRAP 1996)	%NO_x reduction	Cost, $/ton	Status
Cement Kilns	41,009	0 to 50%	1000-2000	Commercial

Process Description:

Inject portion of the fuel downstream of the main flame to create locally reducing conditions where NO_x can be destroyed. Sometimes includes installing a “NO_x fan” to increase burnout. Most commonly applied to preheater/precalciner kilns in which part of the coal is already being fired in the calciner. In this case, airflow is rerouted downstream of the calciner fuel injector.

Air and Fuel Staging as commonly applied to large industrial/utility boilers is discussed under the more commonly referred names technologies Overfire Air and Fuel Reburn

NO_x Reduction:

NO_x reduction is achieved by creating two separate combustion zones. The burner zone is fired fuel-lean to create the high temperatures needed for clinker formation. Limestone calcination, which takes place at temperatures in the range of 1600 to 1800 °F, is accomplished in the second combustion zone in the tower. NO_x reductions as high as 50% can be achieved by controlling the size of the fuel-rich region in the second combustion zone. Conversely, if combustion is fuel-lean or well-mixed in the second zone, NO_x would not be reduced. The ideal stoichiometric ratio in the calciner is 0.7 to 0.8. Some systems do not perform well because the second combustion zone is too fuel-rich ($SR < 0.6$), causing significant NO_x production when the staging air is added.

Cost Information:

Capital cost for the technology includes additional ductwork and controls. This should run between $200,000 and 500,000 depending on the length of new ductwork required. Operating cost should not change unless lower temperatures or locally reducing conditions adversely affect cement quality.

Development Status:

Commercially available.

Practical Considerations:

The technology is easier to implement on preheater/precalciner kilns since special injectors are required to introduce fuel or air into the middle of a rotating kiln. In either case, there must be sufficient residence time at high temperature to complete burnout.

Compatibility with other air pollution control technologies:

Reducing conditions may increase sulfur emissions or require additional SO_2 emission controls.

Process: Air or Fuel Staging

Secondary Environmental Impacts:

None expected.

References:

Dusome D. (1993). “Staged Combustion for NO_x Control at the Calaveras Tehachapi Plant”, presented to the Portland Cement Association.

Nielsen, P.B. et al. (1990). “An Overview of the Formation of SO_X and NO_X in Various Pyroprocessing Systems”, IEEE Cement Industry Technical Conference.

Johnson, S.A. and Haythornthwaite, S., “Summary of Available NO_x Control Techniques for the Cement Industry”, submitted to the Portland Cement Association, Skokie, IL, 1998.

Process: Batch/Cullet Preheating

Category	NO$_x$, TPY (WRAP 1996)	%NO$_x$ reduction	Cost, $/ton	Status
Glass Manufacturing	5,033	5-25%	890-1,040	Commercial

Process Description:

Batch and cullet (recycled glass) preheating can be applied by direct preheating, indirect preheating and Edmeston EGB Filter. Direct preheating requires direct contact between the flue gas and the raw material in a cross-counter flow and incorporates a bypass that allows furnace operation to continue when preheater use is either inappropriate of impossible. The indirect preheater is in principle a cross-counter flow, plate heat exchanger. The Edmeston electrified granulate bed (EGB) filter system is a hybrid between an electrostatic precipitator for dust removal and a direct cullet preheater.

NOx Reduction:

Cullet preheating is primarily an energy saving technique (savings between 10-20%), but its practice reduces NO$_x$ emissions due to lower fuel requirements and lower furnace temperatures.

Cost Information:

Capital costs generally range from $42K-110K[illegible]conomics are strongly dependent on the capacity of the furnace and the preheater.

Development Status:

Commercially available

Practical Considerations:

Cullet preheating systems can be installed at any existing glass melting furnace with greater than 50% cullet in the batch. For economic reasons, the temperature of the waste gas available should be at least 400-450°C, and a cooling of the flue gases by at least 200-250°C is needed. To prevent material agglomeration, the maximum entry temperature of the flue gases should not exceed 600°C.

The design and implementation of the preheating unit should be evaluated with the over-all system configuration. Many technical issues, such as monitoring of the preheating temperature, should be carefully reviewed prior to the implementation.

Compatibility with other air pollution control technologies:

Cullet preheating is compatible with combustion modification techniques and post-combustion technologies.

Secondary Environmental Impacts:

- The use of a direct preheater causes increased emissions of particulate matter (up to 2000 mg/Nm^3) and secondary particulate abatement is necessary.
- Direct preheating reduces acidic compounds, SO$_2$, HF, and HCl by up to 60%, 50%, and 90% respectively (difference before and after cullet bed).

References

European IPPC Bureau. “Reference Document on Best Available Techniques in the Glass Manufacturing Industry.” Seville, Spain, October, 2000.

Process: Catalytic Combustion

Category	NO_x, TPY (WRAP 1996>100 TPY)	%NO_x reduction	Cost, $/ton	Status
Combustion or Gas Turbines	25,278	> 80%	> 500	Commercial

Process Description:

Catalytic combustion reduces NO_x formed from the combustion process by reducing the combustion temperature to reduce thermal NO_x. The fuel and air are premixed into a fuel-lean mixture (fuel/air ratio of approximately 0.02) and then pass into a catalyst bed. In the bed, the mixture oxidizes without forming a high-temperature flame font. Peak combustion temperatures can be limited to below 2800 °F, which is below the temperature at which significant amounts of thermal NOx begin to form. Catalytic combustors can also be designed to operate in a rich/lean configuration. In this case, the air and fuel are premixed to form a fuel-rich mixture, which passes through a first stage catalyst where combustion begins. Secondary air is then added to produce a lean mixture, and combustion is completed in a second stage catalyst bed.

NO_x Reduction:

According to one developer of the technology, catalytic combustion has been demonstrated to achieve 3 ppm NO_x on a 1.5 MW gas turbine[illegible] NO_x level of 3.3 ppm was achieved on a General Electric Frame 9 test stand.

Cost Information:

Costs referenced above are preliminary and based on DOE reference below.

Development Status:

Commercially available.

Practical Considerations:

Catalytic combustion techniques apply to all combustor types and are effective on both diesel- and gas-fired turbines. The technology has a limited operating range, and thus cannot be applied to gas turbines subject to rapid load changes.

Compatibility with other air pollution control technologies:

Compatible with post-combustion technology.

Secondary Environmental Impacts:

None expected.

References:

NESCAUM, “ Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers and Internal Combustion Engines: Technologies and Cost Effectiveness,” December 2000

U.S. Environmental Protection Agency. “Alternative Control Techniques Document-NO_x Emissions from Stationary Gas Turbines.” EPA-453/R-93-007, Research Park Triangle, NC, January 1993.

DOE, “Cost Analyses of NO_x Control Alternatives for Stationary Gar Turbines”, November 1999.

Process: DLN (Fuel-lean combustion)

Category	NO_x, TPY (WRAP 1996>100 TPY)	%NO_x reduction	Cost, $/ton	Status
Turbines	25,278	70%	1,000-2,000	Commercial

Process Description:

Dry Low NO_x (DLN) is a combustion technology for gas turbines that enables gas-turbine combustors to produce low NO_x emission levels without diluents (such as water or steam) or catalysts. DLN technology utilizes a lean, premixed flame as opposed to a turbulent diffusion flame, a gas turbine equivalent of the LNB.

NO_x Reduction:

Engines from 3-10 MW retrofit with DLN achieved 42 ppm NO_x emissions, corresponding to reductions in the range of 60-83%. New and retrofit turbines in the larger, power plant sizes (over 50 MW) have been retrofitted to below 9 ppm of NO_x.

Cost Information:

The cost of NO_x reduction by DLN is very sensitive to the capacity factor of the turbine. There is also substantial variation in capital cost measured in terms of dollars/horsepower ($/hp) due to different turbine types and variations in turbine design. Reported costs in case studies show capital costs ranging from $750K-1,950K (4,700 hp at $160/hp and 13,000 hp at $150/hp). These are total project costs that owners attributed to the project, which may include project management or other charges associated with the project beyond the equipment and installation.

Development Status:

Commercially available

As of August 2000, about 50 turbines had been retrofitted and over 500 new turbines were operating with DLN technology.

Practical Considerations:

Because DLN combustor technology operates under conditions that are much closer to the flammability limit than the conventional combustor technology, there is a significant risk of flame instability. Manufacturers have developed improved electronic turbine controls to address this problem. Some early experience has also found combustor liners failing after only about 5,000 hours compared to over 20,000 hour lifetime for conventional technology. Similarly, manufacturers have developed improved liners to address this problem.

Other considerations are:

- DLN is achievable with fuels that can be premixed and are low in fuel nitrogen content, such as natural gas. Turbines that must maintain low NOx levels while operating on fuel oil may not be compatible with DLN.
- Achieving low NO_x across the full load range requires a sophisticated combustor design, often with variable operating modes in order to maintain flame stability.

Process: DLN (Fuel-lean combustion)
• The DLN combustor is typically larger than a conventional combustor and can have more limited operating ranges.
Compatibility with other air pollution control technologies: Compatible with post-combustion technology (SCR, SNCR).
Secondary Environmental Impacts: None expected.
References: NESCAUM, “ Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers and Internal Combustion Engines: Technologies and Cost Effectiveness” December 2000.

Process: Flue Gas Recirculation (FGR)

Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Oil/Natural gas boilers	32,910	40-80%	500-3,000	Commercial
Refinery Process Heaters	9,311	(combined with LNB)	5,900	Commercial

Process Description:

Flue Gas Recirculation (FGR) simply refers to a NO_x reduction approach that involves reintroducing some flue gas (5% to 15%) into the combustion air (or directly into the burner) to suppress flame temperatures and minimize NOx formation.

This technology usually involves a dedicated FGR fan to recirculate the flue gas back to the burner front and it is most applicable to gas fired applications. This is because its main benefit is in the minimization of thermal NO_x (NO_x formed from nitrogen in the combustion air), as opposed to fuel-NO_x (NO_x formed from fuel-bound nitrogen). Since in oil and coal sources a significant fraction of NO_x comes from "fuel-NO_x", FGR is less effective in such applications

NO_x Reduction:

NO_x reductions from FGR on gas-fired sources can be in the range of 40% to 80%.
FGR is often used in combination with LNBs and discriminating between the relative NOx reduction contributions is difficult in some cases.

Cost Information:

The main costs associated with FGR involve the retrofit of the FGR fan(s) and required ductwork to route the flue gas to the burner front. Costs in the range of $10 - $20/kW are expected for power generation sources

Development Status:

FGR is a well-proven   technology in commercial operations for many years. Variations of the general concept include Induced FGR where the gas recirculated to the burner zone through an eductor, as well as recirculated to individual burners as opposed to the combustion air windbox for mixing with the combustion air prior to entering the burners.

Practical Considerations:

As mentioned above, FGR is mostly appropriate for gas-fired applications. Its effectiveness on oil and coal reduce its "appeal" to such sources

Care is necessary to ensure that the amount of FGR does not compromise boiler safety by diluting oxygen concentration in the combustion air to unsafe levels

Process: Flue Gas Recirculation (FGR)

Compatibility with other air pollution control technologies:

FGR is used in combination with LNB’s and OFA.

FGR is also compatible with post combustion NO_x technologies although the overall cost effectiveness needs to be addressed case-by-case.

Secondary Environmental Impacts:

None expected.

References:

EPRI, “Retrofit NO_x Control Guidelines for Gas- and Oil-Fired Boilers”, Final Report, December 1993.

Poole, L., “Houston Galveston Area NO_x Abatement Industries Perspective,” present at the Council of Industrial Boiler Owners, NO_x Control XV Conference, Houston, TX, August 2002.

Process: Fuel Reburn

Category	NO_x, TPY (WRAP 1996>100 TPY)	%NO_x reduction	Cost, $/ton	Status
Coal-fired boilers	607,748	30-60%	500-2,000	Commercial
Wood/Biomass boilers	9,776	40-60%	300-3,000	Commercial
Glass Melters	5,033	50-65%	“moderate”	Commercial

Process Description:

Reburning, while generically included in the “Combustion Modification” category of NO_x control technologies, differs from the others (BCM, LNB and OFA) by “destroying” NO rather than by minimizing its formation. Fuel is introduced above the main burner zone in the furnace, creating a fuel-rich (reducing) atmosphere in which NO_x formed in the main burner zone is destroyed by reacting with hydrocarbon and nitrogen compounds. The hardware needed for reburning includes reburn fuel burners or nozzles and overfire or burnout air ports (see discussion on fuel-lean reburn for deviations from this). The level of complexity of a particular system depends mostly on the choice of the reburn fuel itself (gas, coal, oil, orimulsion), as well as on the status and capability of the existing boiler (e.g., the burner/boiler control system).

NO_x Reduction:

Full load NO_x reductions with reburning can be expected to range from 35% to 60% depending on factors such as:

- reburn fuel type and quantity; typically the reburn fuel needs to provide 15-20% of the total heat input if it is gas or 25-30% if coal to obtain 50-60% ΔNO_x
- initial NO_x level
- “tolerance” of negative impacts (e.g., efficiency loss, ash quality)

At low loads, NO_x reduction may fall to the 20-40% range, depending on the burner zone stoichiometry and low load operating characteristics of the boiler (e.g., operating at high excess air to control reheat temperature). Reburning, like SNCR and SCR, may be thought of as a “dial-in” technology in that NO_x reductions will be a function of the amount of reburn fuel (or the amount of nitrogen compound reagent in the case of SNCR and SCR). This feature may make it particularly attractive for compliance scenarios based on seasonal use, averaging and/or trading.

Cost Information:

In general, the capital costs range from $15/kW to $30/kW for gas reburn and $30/kW to $60/kW when using coal as the reburn fuel. Operating costs are mainly driven by fuel cost differential (certainly gas vs coal). For other fuels (e.g. coal/orimulsion reburning), fuel preparation costs become more important (micronization, atomization) as there is little or no fuel cost differential.

Retrofit schedules are directly related to the scope of the retrofit requirements. In most cases, 3-6 weeks are adequate for a reburn retrofit.

Process: Fuel Reburn

Development Status: Commercial

While reburning does not account for a significant fraction of installed NO_x reduction technologies compared to LNBs, SNCR and SCR worldwide, it is gaining acceptance, and a number of recent activities suggest it has become a viable strategic option for NOx control. This increase in interest is due to two key factors, among others: (1) increased experience and encouraging results, which increase the level of comfort with the technology; and (2) the "proliferation" of advanced reburn technologies, each with its own features, advantages and disadvantages. These "advanced" reburning options involve enhancements of the conventional approach, with features ranging from combinations with SNCR to the outright avoidance of overfire air, as in fuel-lean gas reburn (FLGR).

Practical Considerations:

Boilers with the following design and operating characteristics are expected to be more suitable candidates for reburning:

- firing low-sulfur coals (e.g., less propensity for waterwall corrosion)
- low baseline unburned carbon (e.g., to minimize ash salability impacts).
- favorable cross-section/height profiles (e.g., tall boilers which provide for adequate mixing/residence time to maximize effectiveness).
- gas availability, very efficient/effective coal pulverizers (e.g., approaching micronization) or access to orimulsion for the reburn fuel

Of major importance is the choice of reburn fuel. The increasing experience with coal and orimulsion dictates that these must be considered in light of cost, availability, deliverability and overall project objectives. However, the use of natural gas provides benefits from lower maintenance costs (e.g., less demand on pulverizers) and lower emissions of other pollutants (particulate, SO_x, CO_2).

Compatibility with other air pollution control technologies:

Reburn Technology can be implemented with both Low NO_x combustion approaches (e.g. LNBs) and post combustion technologies (SNCR/SCR). However, the overall NO_x reductions are not strictly additive and careful evaluation is required to ensure cost effective strategies.

Secondary Environmental Impacts:

Reburn technology has the potential to effect both positive and negative secondary environmental impacts depending on factors such as the reburn fuel, main combustion and reburn zone stoichiometries, boiler physical characteristics, etc.

The following are potential impacts that must be analyzed on an individual unit basis

- CO may increase due to stoichiometry in the reburn zone
- LOI may increase due to stoichiometries and OFA design

Process: Fuel Reburn
- SO_2/CO_2 benefits when reburn fuel is gas (proportional to gas input)
References: NESCAUM, “Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers”, June 1998. EPRI, “Retrofit NO_x Controls for Coal-Fired Utility Boilers – 2000 Update”, EPRI Final Report, December 2000. Folsom, B. “Field Experience with Reburn NOx Control”, ICAC Forum 2000, Arlington, VA. March 2000.

Process: High Energy Ignition System (HEIS)

Category	NO_x, TPY (WRAP 1996>100 TPY)	%NO_x reduction	Cost, $/ton	Status
Reciprocating Engines	86,210	50% - 80%	115 - 200+	Commercial

Process Description:

HEIS technology, also known as plasma ignition, provides a continuous electrical discharge at the gap of a conventional spark plug for 10 to 90 degrees of crankshaft rotation as opposed to traditional spark ignition where the life of the spark is only a fraction of a degree of crankshaft rotation. The extended energy ensures that ignition will occur even in the leanest of conditions. A rich mixture is ignited in a small ignition cell located in the cylinder head. The ignition cell flame passes to the cylinder where it provides a uniform ignition source.

NO_x Reduction:

Laboratory tests and case studies have shown NO_x emissions in the range of 2.5 to 3.0 g/bhp-hr while maintaining acceptable engine operation. Emissions of 2.5 b/bhp-hr were achieved on a 2,750-bhp engine, amounting to an 84% reduction from the uncontrolled level.

Cost Information:

Cost information was not widely reported. Cost range indicated above was taken from the NESCAUM reference below.

Development Status:
Commercially available

HEIS has been installed on numerous engines to meet NO_x RACT requirements in the range of 2.5 to 3.0 g/bhp-hr in the Eastern United States. Several users have reported over 80% reduction in NO_x emissions.

Practical Considerations:

HEIS technology can be used only in lean-burn, natural gas-fired spark ignition engines. This technique can be retrofit to turbocharged 2- and 4-cycle engines.

Compatibility with other air pollution control technologies:

Compatible with post-combustion NO_x technologies (SCR, NSCR). However, the overall NO_x reductions are not strictly additive and careful evaluation is required to ensure cost effective strategies.

Secondary Environmental Impacts:

In most cases, NO_x reductions have been accompanied by increased power output and increased fuel economy.

References:

Edgerton, S. W., Lee-Greco, J., and Walsh, S. "Stationary Reciprocating Internal Combustion Engines Updated Information on NO_x Emissions and Control Techniques (Final Report)." EPA contract No. 68-D98-026, EC/R Incorporated, Chapel Hill, NC, August 29, 2000.

NESCAUM, " Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers and

Process: High Energy Ignition System (HEIS)
Internal Combustion Engines: Technologies and Cost Effectiveness," December 2000. State of New Jersey Department of Environmental Protection. "State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines." Trenton, NJ, July, 1997. Alternative Control Techniques Document: NO_x Emissions from Stationary Reciprocating Internal Combustion Engines. EPA Document No. EPA-453/R-93-032, July 1993.

Process: High-Pressure Fuel Injection

Category	**NO$_x$, TPY (WRAP 1996>100 TPY)**	**%NO$_x$ reduction**	**Cost, $/ton**	**Status**
Reciprocating Engines	86,210	~80%	N/A (less than LEC)	Commercial

Process Description:

High-Pressure Fuel Injection represents a “second generation” Low Emission Combustion (LEC), according to one vendor of NO$_x$ control equipment and retrofit services. The technology uses high pressure to enhance the mixing of air and fuel in the combustion cylinder under fuel lean conditions. This technique reduces the quantity of excess air in comparison to LEC, diminishing the turbocharging and intercooling retrofit requirements.

NO$_x$ Reduction:

Tests from a large (~5,000 bhp) turbocharged Clark engine showed 80% NOx reduction. May be comparable to LEC reductions.

Cost Information:

Less than LEC because the technology does not require pre-combustion chambers or as much excess air, thus reducing the degree of turbocharging and intercooling required.

Development Status:
Commercially available

Considered emerging in 2000.

Practical Considerations:

An LEC retrofit vendor stated that NO$_x$ emissions cannot be reduced to 2 g/bhp-hr through the use of a high-pressure fuel system alone. Less stringent regulatory requirements cans be met with a combination of ignition timing adjustment, high-pressure fuel injectors, and improve A/F ratio and ignition system controls.

Compatibility with other air pollution control technologies:

Compatible with post-combustion NO$_x$ technologies (SCR, NSCR). However, the overall NO$_x$ reductions are not strictly additive and careful evaluation is required to ensure cost effective strategies.

Secondary Environmental Impacts:

None expected.

References:

Edgerton, S. W., Lee-Greco, J., and Walsh, S. “Stationary Reciprocating Internal Combustion Engines Updated Information on NO$_x$ Emissions and Control Techniques (Final Report).” EPA contract No. 68-D98-026, EC/R Incorporated, Chapel Hill, NC, August 29, 2000.

National Center for Environmental Research, U. S. EPA Office of Research and Development. “1994 Phase II Abstracts: Plasma Ignition Retard for NO(x) Reductions.” http://es.epa.gov/ncerqa_abstracts/sbir/94/topics43.html.

Process: “Intelligent” Combustion Controls

Category	NO_x, TPY (WRAP 1996)	%NO_x reduction	Cost, $/ton	Status
Coal-Fired Boilers	607,748	0-30%	100-300	Commercial
Oil/Gas Boilers	32,910	0-30%	100-500	Commercial
Wood/Biomass Boilers	9,776	0-20%	200-500	Commercial

Process Description:

Sensors and computer software programs are used to control air-fuel ratio to individual burners. Conventional combustion systems provide measured airflow to the windbox (that feeds all burners) and to each pulverizer (that feeds from two to eight burners). However, coal flow to individual burners may deviate by as much as 50%, while airflow to each burner may deviate by over 20%. Measuring and controlling (using existing or new control valves) these quantities at each burner allows the boiler to operate with lower excess air or slightly staged. Sensors are also available to monitor post-combustion processes. Online measurements of unburned carbon and CO provide feedback for burner adjustments. Other sensors evaluate flame quality, furnace temperature, or boiler heat transfer. Software can be rule-based or neural net. Usually the new software resides on the operator’s digital control system (DCS).

NO_x Reduction:

Full -load NO_x reductions with combustion monitoring and tuning can be expected to range from 0% to 30% depending on factors such as:

- Current state of “out of tune” combustion system.
- Initial NO_x level.
- Operational flexibility of the burner/furnace design.

The highest NO_x reductions are usually found on boilers that are able to bias their fuel input to lower burners and bias the airflow to upper burners. At low loads where there may be more operating flexibility, NO_x reduction may improve to the 20-40% range, depending on the burner zone stoichiometry and low load operating characteristics of the boiler (e.g., operating at high excess air to control reheat steam temperature).

Cost Information:

In general, the capital costs for combustion monitoring and tuning are less than $1M per boiler. Operating costs are mainly driven by additional labor to maintain the new equipment. Often the installation of this technology is driven by the potential to reduce boiler operational expenses. For example, if total airflow is minimized, boiler efficiency can be increased. Reducing unburned carbon in the ash residue will not only increase boiler efficiency but also could improve salability of this byproduct to the cement industry.

An outage is generally not required when implementing this technology, but coal-flow sensors and adjustable orifices are best installed when a mill is out of service.

Process: “Intelligent” Combustion Controls

Development Status:

Commercially available. Many of the sensors, however, are relatively new and do not have a track record for reliability and dependability. Since each application of the technology is custom-engineered, there may be a steep learning curve for every user. For now, each installation also requires onsite presence (for a few weeks) from the supplier or other combustion expert to achieve best results.

Practical Considerations:

Boilers with the following design and operating characteristics are expected to be more suitable candidates for combustion monitoring and tuning:

- Combustion equipment must be in good operating condition. The technology will not be able to overcome such factors as poor coal fineness or failure of burner parts.
- Favorable cross-section/height profiles (e.g., tall boilers which provide for adequate mixing/residence time to maximize effectiveness).
- Excess coal pulverizer capacity so that fuel biasing can be maximized.

Of major importance is acceptance from boiler operators. If operators want to stick with old procedures and operating conditions, the effectiveness of the technology may not be realized.

Compatibility with other air pollution control technologies:

Combustion monitoring and tuning can be implemented with both Low NO_x combustion approaches (e.g. LNBs) and post combustion technologies (SNCR/SCR). However, the overall NO_x reductions are not strictly additive and careful evaluation is required to ensure cost effective strategies.

Secondary Environmental Impacts:

Combustion monitoring and tuning has the potential to affect both positive and negative secondary environmental impacts depending on factors such as the fuel, burner stoichiometries, boiler physical characteristics, etc.

The following are potential impacts that must be analyzed on an individual unit basis

- CO may increase due to stoichiometry in the burner zone
- LOI may increase due to increased staging
- ESP performance may degrade with increased LOI

References:

Power Plant Optimization Guidelines, EPRI Report, December 1998

Alternative Control Techniques Document: NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers. EPA Document No. EPA-453/R-94-022, July 1994.

Alternative Control Techniques Document: NO_x Emissions from Utility Boilers. EPA Document No.

Process: “Intelligent” Combustion Controls
EPA-453/R-94-023, July 1994. Fuller, T., “Field Experience with the Flame Doctor^{TM} System”, EPRI/DOE/EPA Mega Symposium, Washington, May 2003 Kohn, D. “Combustion Optimization Case Studies & Emerging Applications”, EPRI/DOE/EPA Mega Symposium, Washington, May 2003

Process: Iron Slag Addition (CemStar)				
Category	**NO_x, TPY (WRAP 1996)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Cement Kilns	41,009	12-30%	0-100	Commercial

Process Description:

Change cement formulation by adding waste iron to lower clinkering temperature and suppress NO_x. The iron waste is usually supplied from local steel production facilities, which limits the technology to certain geographical areas.

NO_x Reduction:

NO_x reduction is achieved by reducing clinkering temperature as well as the required heat input to produce a ton of clinker. The technology reduces total NO_x emissions by about 20 to 30%, and also may increase clinker production.

Cost Information:

Iron addition provides an overall economic benefit while reducing total NO_x emissions. The technology is currently being used at several cement plants for its original purpose of increasing production capacity. There are no capital costs for installing the technology. Operating and maintenance costs depend on the cost of the iron (shipping can be a large portion of this cost).

Development Status:

Commercially available.

Practical Considerations:

There is a limit to how much iron that can be incorporated into the clinker. Cement product specifications may limit or prevent use of this technology for some products.

Compatibility with other air pollution control technologies:

Should not affect other control systems.

Secondary Environmental Impacts:

None expected.

References:

NESCAUM, “Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines; Technologies and Cost Effectiveness.” December 2000.

Process: Kiln temperature control

Category	NO_x, TPY (WRAP 1996)	%NO_x reduction	Cost, $/ton	Status
Cement Kilns	41,009	0 to 20%	200-500	Commercial

Process Description:

Add temperature-monitoring device to kiln controls to minimize high-temperature excursions where more NO_x is emitted.

NO_x Reduction:

NO_x reduction is achieved by measuring a characteristic flame-zone temperature and then controlling heat input to maintain that temperature. Without direct temperature measurement, temperatures fluctuate within a wide range since clinker formation is an exothermic reaction. When clinker formation slows down or stops, temperatures fall. Operators respond with a large burst of fuel that sends temperature up by as much as 500 °F. Then they back off the fuel input. Temperature measurement helps operators avoid losing clinker formation and thus maintain relatively steady kiln temperatures.

Cost Information:

Capital cost for the technology includes installation of a continuous temperature monitor along with control system upgrades to tie the temperature signal into the coal feed rate. Operating cost should not change unless lower temperatures adversely affect cement quality.

Development Status:

Commercially available.

Practical Considerations:

The dynamics of a cement kiln are very difficult to control, even with direct temperature measurement and control. Each kiln will react differently. It will require considerable operator experience to minimize the temperature on each kiln.

Compatibility with other air pollution control technologies:

Should not affect other control systems.

Secondary Environmental Impacts:

None expected.

Process: Kiln temperature control
References: U.S. Environmental Protection Agency. “Alternative Control Techniques Document: NO_x Emissions from Cement Manufacturing.” EPA Document No. EPA-453/R-94-004, January 1994. Johnson, S.A. and Haythornthwaite, S., “Summary of Available NO_x Control Techniques for the Cement Industry”, submitted to the Portland Cement Association, Skokie, IL, 1998.

Process: Low-Emission Combustion (LEC)

Category	NO_x, TPY (WRAP 1996>100 TPY)	%NO_x reduction	Cost, $/ton	Status
Reciprocating Engines	86,210	80-90%	190-700	Commercial

Process Description:

NO_x formation from a spark-ignited engine is highest when the mixture is slightly fuel-lean. LEC enhances the effectiveness of the air/fuel ratio method by enabling much deeper leaning without the adverse effects associated with lean mixtures. Additional combustion air acts as a heat sink, lowering the temperature in the cylinder and reducing NO_x formation. Deeper leaning can be achieved by relocating the spark plug to a precombustion chamber (may use High-Energy Ignition, see associated description) where the mixture is somewhat richer than in the cylinder. Early sparking avoids problems associated with ignition and misfiring that can result form leaning the mixture. Some smaller engines use an “open chamber” LEC design instead of a precombustion chamber. These designs typically incorporate improved air-fuel mixing systems to achieve stable combustion under very lean conditions.

NO_x Reduction:

Large, stationary spark-ignition engines usually achieve 80% NOx reduction through a LEC Retrofit. A NOx emission level of 125 ppm (at 15% oxygen) is an achievable exhaust NOx value. Up to 90% reduction can be achieved in natural gas engines, and about 60-70% for landfill gas engines (probably due to lower initial NOx from the lower heating-value landfill gas).

Engines with open-chamber LEC technology typically are designed for excess air levels only slightly above 50%, while engines with precombustion chambers typically are designed for excess air levels of 75-100%. Consequently, prechambered engines have generally lower NOx emissions than do open-chamber models.

Cost Information:

The capital cost of retrofitting these engines depends on the engine BHP. For engines firing a single fuel, retrofits have been implemented costing $340/hp for 3400hp engines. A lower capital cost is expected for smaller, medium-speed engines, about $200/hp. Dual-fuel engines have much greater capital costs. For these engines (larger than 1,000 hp), the capital cost can be estimated by

Capital Cost = $405,000 + ($450 x hp).

Retrofitting a 2,500 hp engine is projected to cost $615/hp.

Development Status:

Commercially available

The California Air Resources Board considers LEC Retrofit a Reasonably Available Control Technology (RACT) for large spark-ignition engines. LEC based on precombustion chamber technology has been in use for over 20 years. All major manufacturers of lean-burn spark ignition engines offer LEC-equipped models. Retrofit kits are also available.

Process: Low-Emission Combustion (LEC)

Practical Considerations:

Available for spark-ignition engines fired with gaseous fuels including dual-fuel engines operating in dual-fuel mode (as opposed to firing only diesel fuel). LEC can cause some fuel efficiency decrease. A reasonable fuel efficiency penalty is estimated to be on the order of 0.5%.

Turbocharging and intercooling are required to avoid derate. In retrofit situations, this typically involves upgrading or replacing the turbocharger and intercooler, or adding this equipment.

Other equipment associated with increased air flows may also need to be modified for LEC, such as the air intake and filtration system, the intercooler radiator, and the exhaust system and muffler. To maintain the optimum A/F ratio, an automated A/F ratio controller typically is used.

The challenge with very lean combustion is to achieve proper ignition and stable combustion. Vendors of LEC technology (i.e., engine manufacturers and third-party retrofitters) have met these requirements with some combination of improved combustion chamber design, enhanced air-fuel mixing, and improved ignition systems.

Compatibility with other air pollution control technologies:

Compatible with post-combustion NOx technologies (SCR, NSCR). However, the overall NO$_x$ reductions are not strictly additive and careful evaluation is required to ensure cost effective strategies.

Secondary Environmental Impacts:

Emissions of products of incomplete combustion can increase.

References:

Edgerton, S. W., Lee-Greco, J., and Walsh, S. “Stationary Reciprocating Internal Combustion Engines Updated Information on NO$_x$ Emissions and Control Techniques (Final Report).” EPA contract No. 68-D98-026, EC/R Incorporated, Chapel Hill, NC, August 29, 2000.

NESCAUM. “Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines; Technologies and Cost Effectiveness.” December, 2000.

State of California Air Resources Board. “CAPCOA/ARB Proposed Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Internal Combustion Engines (DRAFT).” Sacramento, CA, December, 1997.

State of New Jersey Department of Environmental Protection. “State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines.” Trenton, NJ, July, 1997.

U.S. Environmental Protection Agency. “Alternative Control Techniques Document – NO$_x$ Emissions from Stationary Reciprocating Internal Combustion Engines.” EPA-453/R-93-032, July, 1993.

Cooper-Bessemer. Facsimile from J. W. Hibbard to W. Neuffer, U. S. EPA. Information on Low Emission Combustion. Cooper-Bessemer, Cooper Energy Services, Mount Vernon, OH. March 3, 1999. 4pp.

Dresser-Rand. Facsimile from C. F. Willke to W. Neuffer, U. S. EPA. Information on Low Emission Combustion. Dresser-Rand Services, Painted Post, NY. May 7, 1999. 2pp.

Process: Low-NO_x Burners

Category	NO_x, TPY (WRAP 1996)	%NO_x reduction	Cost, $/ton	Status
Coal-Fired Boilers	607,748	30 to 60%	200-1000	Commercial
Cement Kilns	41,009	0 to 20%	500-1000	Commercial
Oil/NG Boilers	32,910	30 to 60%	200-1000	Commercial
Glass Manufacturing	5,033	~ 40%	790-1,680	Commercial
Refinery Process Heaters	9,311	30 to 60%	5,900 (with FGR)	Commercial

Process Description:

LNB’s operate on the principal of carefully controlling the rate of mixing of air and fuel within the flame so that peak flame temperatures are low and fuel-bound nitrogen is released in a region where the concentration of oxygen is very low. This inhibits the formation of both fuel and thermal NOx by reducing the concentration of oxygen in the flame zone. Most LNB’s work by limiting the amount of air in the primary flame creating a central fuel-rich flame core. Additional air is introduced to surround the primary flame where the temperature is lower, limiting thermal NO_x formation. A few low-NO_x burners split the coal flow into two or more streams to create multiple fuel-rich regions. One Japanese burner concentrates the coal-primary air mixture, and introduces the dilute coal stream downstream of the burner while air is introduced only to the primary flame. The fuel introduced into the primary flame zone results in a high temperature fuel rich central flame. The balance of coal is added outside the primary flame where it burns at a lower temperature.

NO_x Reduction:

Full load NO_x reductions with Low-NO_x Burners can be expected to range from 30% to 60% depending on factors such as:

- Fuel type.
- Initial NO_x level.
- Excess air
- Operational flexibility of the boiler or furnace.

For coal-fired boilers, NO_x emissions rates as low as 0.15 lb/MBtu are achievable, particularly when burning low rank coals. However, the fuel nitrogen content of coal is such that significantly lower emission rates are probably not possible with coal. Lower emission rates can be achieved with natural gas. Installing Low-NO_x burners is usually the first step taken to reduce NO_x emissions.

Cost Information:

In general, the capital costs for burners range from $10,000 to 50,000 per burner plus installation. The lower end of this range applies when existing burners are modified instead of replaced to achieve lower NO_x. Operating costs are negligible unless increased unburned carbon results in lost revenues from ash sales. An outage is generally required when implementing this technology, but coal-flow sensors and adjustable orifices are best installed when a mill is out of service.

Process: Low-NO$_x$ Burners

Development Status:

Commercially available.

Practical Considerations:

Since low-NO$_x$ Burners usually produce longer flames, the size and shape of the furnace could cause problems for some installations. Flame impingement on sidewalls or rear wall can result in ash deposits, corrosion, or unacceptable unburned carbon in the flue gas. Most burners have optional configurations to shape the flame at the expense of less NO$_x$ reduction.

Compatibility with other air pollution control technologies:

Low-NO$_x$ burners can be implemented with other NO$_x$-control technologies such as OFA, SNCR, or SCR. In general, the NO$_x$ reduction achieved with LNB make post-combustion NO$_x$ control technologies more cost-effective.

Secondary Environmental Impacts:

Low-NO$_x$ burners can cause both positive and negative secondary environmental impacts depending on factors such as the fuel, burner stoichiometries, boiler physical characteristics, etc.

The following are potential impacts that must be analyzed on an individual unit basis

- CO may increase due to stoichiometry in the burner zone
- LOI may increase due to increased staging
- ESP performance may degrade with increased LOI or finer particulate.

References:

EPRI, “Retrofit NO$_x$ Controls for Coal-Fired Utility Boilers – 2000 Update”, EPRI Final Report, December 2000

EPRI, “Retrofit NO$_x$ Controls for Coal-Fired Utility Boilers – 1996 Update Addendum”, May 1997

Process: Low-NO_x Calciners

Category	NO_x, TPY (WRAP 1996)	%NO_x reduction	Cost, $/ton	Status
Cement Kilns	41,009	30 to 50%	1000-5000	Commercial

Process Description:

Replace the riser duct in existing preheater/precalciner kilns with new equipment designed for staged combustion. The new duct has separated air and fuel injection points, and extended residence time downstream of the final air addition point to assure acceptable burnout and minimize CO or hydrocarbon emissions.

NO_x Reduction:

NO_x reduction is achieved by creating two separate combustion zones. The burner zone is fired fuel-lean to create the high temperatures needed for clinker formation. Limestone calcination, which takes place at temperatures in the range of 1600 to 1800 °F, is accomplished in the second combustion zone in the tower. NO_x reductions as high as 50% can be achieved by controlling the size of the fuel-rich region in the second combustion zone. Conversely, if combustion is fuel lean or well mixed in the second zone, NO_x will not be reduced. The ideal stoichiometric ratio in the calciner is 0.7 to 0.8. Some systems do not perform well because the second combustion zone is too fuel-rich ($SR < 0.6$), causing significant NO_x production when the staging air is added.

Cost Information:

Capital cost for the technology includes additional injectors, ductwork and controls. In some cases, the cyclones used to improve gas-solids contact are also replaced. Capital cost range from $500,000 and 5,000,000 depending on how much of the existing tower is replaced. Operating costs should not change unless cement quality degrades due to lower temperatures or locally reducing conditions. An outage is required to install the new equipment.

Development Status:

Commercially available.

Practical Considerations:

Space to fit the newer larger equipment may not be available in all kilns.

Compatibility with other air pollution control technologies:

Reducing conditions may increase sulfur emissions or require additional SO_2 emission controls.

Secondary Environmental Impacts:

None expected.

Process: Low-NO_x Calciners
References: Rother, R. and Kupper, D., “Staged Fuel Supply – An Effective Way of Reducing NO_x Emissions”, Zement-Kalk-Gips, No. 9. 1989.

Process: Mid-Kiln or Tower Tire Injection				
Category	**NO_x, TPY (WRAP 1996)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Cement Kilns	41,009	15-30%	0-1000	Commercial

Process Description:

Cement kilns are normally fired with a single open-pipe burner fueled by coal or natural gas. However, a portion of the main fuel may be replaced by a waste fuel injected in the mid-kiln region of long, wet or dry kilns, or in the calcining region of tower kilns. Special injectors have been designed to time the introduction of two to four tires into the mid-kiln region as the kiln rotates. Due to rotation, tires can only fall into the kiln once per revolution when the door is on top. Alternately, tires can be dropped into the tower where temperatures are high enough to support combustion.

Mid-kiln tire injection is attractive because it not only reduces NO_x but also generates revenue in the form of tipping fees and reduced fuel requirements. Cadence Environmental Energy, a subsidiary of Ash Grove Cement, offers an automated whole-tire injection system, including a fork that picks up the tires and drops them into the kiln through a gate assembly. A second option is to set up a tire shredding operation on site and inject tire flake into the kiln.

NO_x Reduction:

NO_x is lowered by burning some of the fuel at a lower temperature, and by creating pockets of fuel-rich gas as the tires decompose. Hydrocarbons from tire destruction can reduce NO_x formed in the burner flame. Results to date have varied from 15 to 30% NO_x reduction, depending on:

- Kiln type.
- Number of tires injected.
- Injection temperature.

In some installations, a booster fan has been mounted on the kiln downstream of the tire injection point to provide additional burnout air. This "NO_x fan" gets rid of the high CO or smoke emissions caused by the tires, and may allow operation at higher tire injection rates.

Cost Information:

The capital costs for installing a mid-kiln tire injection system are about $2 to 4M. Operating and maintenance costs should not be affected. Often the installation of this technology is driven by the tipping fee revenue generation. If this is possible, injector costs can be recovered within a few years.

An outage is required when implementing this technology, but downtime can be minimized at sites where space is sufficient for installing the injection system ahead of time (without getting in the way of kiln operation).

Development Status:

Commercially available.

Process: Mid-Kiln or Tower Tire Injection

Practical Considerations:

The main purpose of a cement kiln is to produce as much high-quality clinker as possible at the lowest energy cost. Over-feeding tires creates locally reducing conditions that cause smoke, soot, and spoil the naturally occurring sulfur capture in the clinker resulting in higher SO_2 emissions. The practical limit on tire injection is replacement of about 10 to 30% of the fuel, depending on the kiln design. Also, since tires are injected every two minutes, the NO_x emissions rise and fall erratically, making control very difficult.

Compatibility with other air pollution control technologies:

High airflows from the NO_x fans can cause increased carryover of cement kiln dust (CKD) into the exhaust. Reducing conditions in the flame zone increase SO_2 emissions.

Secondary Environmental Impacts:

Combustion monitoring and tuning has the potential to effect both positive and negative secondary environmental impacts depending on factors such as the fuel, burner air-fuel ratio, kiln design, etc.

The following are potential impacts that must be analyzed on an individual unit basis

- CO, hydrocarbons and soot emissions may increase due to tire byproducts escaping the secondary combustion zone.

- SO_2 may increase due to increased staging.

- ESP performance may degrade with increased CKD.

References:

U.S. Environmental Protection Agency, “Alternative Control Techniques Document: NO_x Emissions from Cement Manufacturing.” EPA Document No. EPA-453/R-94-004, January 1994.

“Stick a Fork in It”. Product Brochure from Cadence Inc., 1997.

Process: Non-Selective Catalytic Reduction (NSCR)

Category	NO_x, TPY (WRAP 1996)	%NO_x reduction	Cost, $/ton	Status
IC Engines, rich-burn only	111,488	40-98%	< 500	Commercial

Process Description:

In NSCR, the engine exhaust is routed to a catalyst bed across which NO_x is reduced to nitrogen gas. At the same time, VOC and carbon monoxide are oxidized to water and carbon dioxide. Because the catalyst reduces emissions all three of these pollutants, NSCR is often referred to as a “three-way catalyst” system. These systems are similar to the catalytic converters used on automobiles.

For an NSCR system to operate optimally (i.e., to minimize NO_x emissions), the inlet exhaust stream must have very low oxygen content, as well as proper concentrations of NO_x, hydrocarbons, and carbon monoxide. This requires initial engine adjustments, followed by careful monitoring of oxygen content in the exhaust. For this reason, an automatic air-fuel (A/F) ratio controller typically is used to regulate the exhaust oxygen content entering the catalyst bed. The controller adjusts the A/F ratio based on input from an oxygen sensor upstream from the catalyst bed.

Because of the requirement for low oxygen content, NSCR systems are limited to rich-burn SI engines.

NO_x Reduction:

This source indicates that these catalyst systems reduce NO_X emissions by over 98 percent, while reducing VOC by 80 percent and carbon monoxide by over 97 percent. NO_x levels in the range of 0.1 to 1.0 g/bhp-hr have been achieved.

Cost Information:

Capital cost for NSCR includes the catalyst as well as the addition of oxygen sensors and controls. Catalyst replacement generally occurs after about 20,000 hours of operation.

Development Status:

Commercial. Information from vendors of NSCR systems indicates that NSCR three-way catalysts have been installed on over 1,000 IC engines in the United States and have been in use for over 10 years. .

Practical Considerations:

The engine adjustments required to optimize NSCR systems typically reduce the efficiency of the engine, harming fuel economy. The biggest operational problem associated with NSCR has been damage to the catalyst caused by excessive temperature. This is caused when the exhaust stream is too fuel rich. In this situation, the uncombusted natural gas is rapidly oxidized in the catalyst bed, burning it out. At about 1,300 ^oF, the catalyst sustains damage.

Compatibility with other air pollution control technologies:

Enhanced removal of CO and VOC can be achieved.

Process: Non-Selective Catalytic Reduction (NSCR)
Secondary Environmental Impacts: None expected.
References: Manufacturers of Emission Controls Association. "Emission Control Technology for Stationary Internal Combustion Engines." Status Report, July 1997. Edgerton, S. W., Lee-Greco, J., and Walsh, S. "Stationary Reciprocating Internal Combustion Engines Updated Information on NO_x Emissions and Control Techniques (Final Report)." EPA contract No. 68-D98-026, EC/R Incorporated, Chapel Hill, NC, August 29, 2000.

Process: NOxTech				
Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Reciprocating Engines	86,210	90-95%	~ 1000	Commercial

Process Description:

According to product literature, the NOxTech® emission control system, developed by NOxTech Inc., NOxTech is an automated system in which exhaust gases are chemically treated with a nonhazardous liquid chemical. The technology involves replacing the engine exhaust silencer with a reaction chamber where NO_x and reagent react to form nitrogen, water vapor, and carbon dioxide. The non-catalytic chemical reagent is injected into the exhaust at temperatures between 1,400 and 1,500 °F.

NO_x Reduction:

The vendor states that NOxTech has been proven to remove 90-95% of NOx, as seen in the 4,000-bhp diesel-powered generator on Catalina Island.

Cost Information:

Based on vendor literature, self-sustained, gas-phase autocatalysis reduces emissions of NO_x are reduced at costs as low as $1,000/ ton.

Development Status:

Commercially available

As of August 2000, the system has been installed and is operating on several diesel generators in California. Based on commercial performance in these engines, NOxTech has been demonstrated as BACT for some diesel engines.

Practical Considerations:

The exhaust gas must be heated to achieve the temperatures necessary for the NOxTech system reactions. A heat exchanger should be placed downstream from the reactor to reclaim and reuse this heat energy.

Compatibility with other air pollution control technologies:

Compatible with low-NO_x combustion approaches (LNB, combustion modification). Can be used to augment LEC.

Secondary Environmental Impacts:

Technology also potentially removes 60-80% of particulate matter, 90% of VOC, and 50-70% of carbon monoxide from the exhaust, as seen in the 4,000-bhp diesel-powered generator on Catalina Island.

The process produces trace ammonia emissions of less than 2 to 5 ppmv.

Process: NOxTech
References: Edgerton, S. W., Lee-Greco, J., and Walsh, S. “Stationary Reciprocating Internal Combustion Engines Updated Information on NO_x Emissions and Control Techniques (Final Report).” EPA contract No. 68-D98-026, EC/R Incorporated, Chapel Hill, NC, August 29, 2000. NOxTech Inc. “NOxTech® Technology.” website. www.noxtechinc.com/products.htm. NOxTech Inc. Letter and attachments from E. Cazzola to Mary Jo Krolewsky, U. S. EPA Acid Rain Division. April 12, 1999.

Process: Overfire Air (OFA)

Category	NO_x, TPY (WRAP 1996>100 TPY)	%NO_x reduction	Cost, $/ton	Status
Coal-fired boilers	607,748	20-40%	250-600	Commercial
Oil/NG boilers	32,910	40-80%	1,000-2,000	Commercial
Wood/Biomass boilers	9,776	20-60%	200-2,000	

Process Description:

OFA, like LNB's, represents practical approaches to minimizing the formation of NO_x during combustion. Simply, this is accomplished by "controlling" the quantities and the way in which fuel and air are introduced and mixed in the boiler (referred to as staging).

In the case of OFA, the approach consists of diverting some of the combustion air (typically up to about 30%) to dedicated injection nozzles (called OFA ports) located some distance above the burner or main combustion zone. Variations include the design and location of the OFA ports, the supply of air to the OFA (either directly from the windbox, or from a dedicated booster fan).

NO_x Reduction:

OFA, which can be used separately or as a system with LNBs, is capable of NO_x reductions of 20% - 40% from uncontrolled levels, when used alone. The type of boiler (e.g., dry vs. wet-bottom, wall- vs. tangential-fired, NSPS vs. pre-NSPS, etc.) and the type of fuel will influence the actual performance achieved.

Cost Information:

OFA technologies have little or no impact on operating costs (other than the potential for an increase in unburned carbon - efficiency loss -, and the resulting impact on ash disposal options). Retrofit costs are site-specific. As such, the economics of these technologies are driven by capital/retrofit costs which typically range from $5-$10/kW, with the lower range reflecting easier application whereas the higher costs are typically associated with more difficult and involved retrofits.

From a schedule standpoint, OFA retrofit projects can require outages of 3 – 6 weeks, depending on factors such as scope of work, integration with other plant outage requirements, etc.

Development Status: Commercial

OFA and LNB's are the most prevalent in the power industry at present. Plants that have had to comply with Title IV of the CAAA of 1992 have largely used these technologies for compliance. Competing manufacturers have proprietary designs, geared towards application in different boiler types, as well as reflecting their own design philosophies.

Practical Considerations:

Boilers with the following design and operating characteristics are expected to be more suitable candidates for OFA applications:

- firing lower-sulfur fuels (e.g., less propensity for waterwall corrosion)
- low baseline unburned carbon (e.g., to minimize ash salability impacts).

Process: Overfire Air (OFA)

- favorable cross-section/height profiles (e.g., tall boilers which provide for adequate mixing/residence time to maximize effectiveness).

- units with existing burners in good operating condition,

- Potential O&M impacts due to combustion NOx controls include:
  - Change in optimum excess air level: 0.5-1.5 percentage points increase in excess O_2 is possible
  - 3-5 percentage points increase in LOI is possible; in general, as higher NO_x reduction is being sought, the higher the probability for increased LOI (NO_x vs. LOI trade-off)
  - Changes in reheat and superheat steam temperatures (typically lower by 20-50 degrees F) are possible in some applications.

Compatibility with other air pollution control technologies:

OFA technologies are often used in conjunction with LNB's. As a main combustion based NO_x control approach, OFA is fully compatible with other NOx controls including LNB's, reburning (OFA is an integral component of reburning), as well as the post combustion technologies such as SNCR and SCR

Secondary Environmental Impacts:

OFA, like all combustion modification approaches face a common challenge: that of "striking a balance" between NO_x reduction and fuel efficiency. The concern is exemplified by the typically higher carbon levels in the fly ash, which reflect lower combustion efficiency but also the contamination of the fly ash itself possibly making it unsuitable for reutilization (e.g., cement industry).

References:

EPRI, "Retrofit NO_x Control Guidelines for Gas- and Oil-Fired Boilers", Final Report, December 1993.

EPRI, "Retrofit NO_x Controls for Coal-Fired Utility Boilers – 1996 Update Addendum", May 1997.

EPRI, "Retrofit NO_x Controls for Coal-Fired Utility Boilers – 2000 Update", EPRI Final Report, December 2000

Process: Oxy-Fuel Firing

Category	**NO_x, TPY (WRAP 1996)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Glass Manufacturing	5,033	80-85%	2,150-4,400	Commercial

Process Description:

Oxy-fuel melting involves the replacement of the combustion air with oxygen (>90% purity). The technique can be used with either natural gas or oil as the fuel, although the use of gas is more common. The elimination of the majority of the nitrogen form the combustion atmosphere reduces the volume of the waste gases (composed mainly of CO_2 and water vapor) by 70-85 % depending on oxygen purity. In general, oxy-fuel furnaces have the same basic design as recuperative melters, with multiple lateral burners and a single waste gas exhaust port. In the most modern furnaces the geometry is optimized for oxy-fuel firing and minimization. Furnaces designed for oxygen combustion do not currently utilize heat recovery systems to pre-heat the oxygen supply to the burners, due to safety concerns; however, the technique potentially involves substantial energy savings because it is not necessary to heat the atmospheric nitrogen to the temperature of the flames. The formation of thermal NO_x is greatly reduced because the main source of nitrogen in the furnace is much lower.

NO_x Reduction:

Compared to air-fuel fired furnaces, NO_x emissions are generally reduced by 70-90%. This reduction equates to:

- <1 kg/ton glass for fiber and container glass furnaces
- 1-2 kg/ton glass for special glass (without nitrate addition)

The latest versions of oxy-fuel burners combined with optimized furnace design and operation can in some cases reduce emissions to 0.3-0.8 kg NO_x/ton of glass melted. No information is available for emissions from flat glass production, but emissions of 0.5 to 1.5 kg/ton of glass melted are considered likely.

Cost Information:

In general, capital costs for oxy-fuel firing are $1,930K-$9,810K. An important factor in the capital cost is that oxy-fuel furnaces do not have a conventional combustion gas preheat system and so the capital cost is generally lower than for a regenerative or recuperative furnace of comparable pull-rate. In most applications, the determining factor regarding cost effectiveness of oxy-fuel firing will be the difference between the energy savings and the costs of the oxygen compared with the costs of alternative NO abatement techniques.

Development Status:

Commercially available

It is estimated that 5-10% of the world’s glass production is made with oxy-fuel melting, but this figure varies between the sectors. There are several examples of oxy-fuel furnaces operating successfully in the following sectors: container glass, glass wool, special glass (particularly TV glass), continuous filament glass fiber, and frits. Trials have been carried out in the domestic glass sector resulting in good NO_x reduction, but problems occurred with severe foaming. The problems encountered in domestic glass production are similar to those initially encountered in other applications e.g. container glass. Similar

Process: Oxy-Fuel Firing

solutions are likely to be possible but the higher quality requirements make them more difficult to apply. There are several examples of the technique operating successfully for domestic glass production worldwide. Considerable development work is being undertaken and the number of plants and the level of operating experience are increasing.

Practical Considerations:

The merits of oxy-fuel firing vary greatly from case to case depending on furnace size and availability of pure oxygen. The technique is most effectively installed during furnace rebuild. Hot installation may lead to energy savings and to an increased pull rate; however, it is unlikely to result in lower NO_x emissions, and there is a danger of accelerated refractory wear.

Furnace waste-gas temperature can be very high, 1200-1300 °C and will usually require cooling. Due to high water content and concentration of corrosive species, cooling is usually by dilution with air. The higher temperatures associated with the technique can result in higher refractory wear.

Oxygen required for combustion can be supplied either by delivery to the site or by on-site production. Except for very small applications, the amounts of oxygen required usually make it more economical to produce the oxygen on-site.

Compatibility with other air pollution control technologies:

Addition of a cullet preheating system, which can also reduce NO_x and other emissions by reducing the amount of fuel required, can add to the energy savings of oxy-fuel firing by recovering heat from the waste gases. See cullet preheating description.

Secondary Environmental Impacts:

Oxy-fuel firing can also help to reduce overall emissions of volatile materials form the furnace (particulates, fluorides, chlorides etc.), due to reduces gas flow over the melt and in some cases reduced turbulence.

- Particulate emissions in soda-lime glass can be reduced to 0.2-0.3 kg/ton.
- Particulate emissions most effectively reduced for boron containing glasses (up to 50%).
- Reduction in fuel usage leads to lower SO_2 emissions for oil-fired furnaces.

Concentrations of all pollutants may actually be higher due to reduced gas volume, although the absolute emission is reduced. Dilution with cooling air usually brings the concentrations closer to more normal levels.

References:

European IPPC Bureau. “Reference Document on Best Available Techniques in the Glass Manufacturing Industry.” Seville, Spain, October, 2000.

Process: Oxygen-Enhanced Combustion Modifications

Category	NO$_x$, TPY (WRAP 1996)	%NO$_x$ reduction	Cost, \$/ton	Status
Coal-fired Boilers	607,748	30 to 80%	1,000-2,000	Near Commercial
Cement kilns	41,009	0-20%	100-1000	Commercial

Process Description:

In coal-fired boilers, O$_2$ injection is used to improve effectiveness of OFA operation. Small amounts of oxygen are introduced into the burner zone through specially designed lances. The added O$_2$ creates a local hot spot that increases the rate of coal volatile release, encourages more NO$_x$ reduction, and enables more fuel-rich operation where less NO$_x$ is formed. The technology has been demonstrated on a 44-MW coal-fired boiler.

In cement kilns, oxygen lances are used to create a hot spot in the flame zone and achieve higher kiln throughput (increase clinker production). In doing so, NO$_x$ is not reduced but NO$_x$ emission rates (lb. NO$_x$/ton of clinker) goes down in proportion to the increase in production. O$_2$ injection achieves even higher production when cement kiln dust (CKD) is co-injected. The CKD also quenches peak flame temperature to achieve some reduction in thermal NO$_x$ formation.

NO$_x$ Reduction:

In the coal-fired boiler demonstration, conventional OFA reduced NO$_x$ to around 0.35 to 0.40 lb./MBtu. O$_2$ injection lowered the NO$_x$ further to around 0.22 to 0.25 lb./MBtu, while also decreasing LOI and opacity, and allowing better steam temperature control when firing bituminous coal. NO$_x$ reductions down to 0.16-0.19 lb./MBtu were achieved when the unit switched to a blend of 90% sub-bituminous and 10% bituminous coal.

In the cement industry, oxygen injection has achieved 0 to 20% NO$_x$ reduction in conjunction with a 0-5% kiln capacity increase. Increased capacity (when it occurs) is the primary cause of the NO$_x$ reduction.

Cost Information:

The primary cost of all these applications of oxygen-enhanced combustion is the cost of the oxygen. Oxygen required for combustion can be supplied either by delivery to the site or by on-site production. Except for very small applications, the amounts of oxygen required usually make it more economical to produce the oxygen on-site. Capital cost for oxygen storage and delivery systems range from \$100,000 when pipeline gas is used, to \$1,500,000 when on-site storage is required. In general, capital costs are \$1,930K-9,810K when on-site generation is chosen.

An important factor for the capital cost of oxy-fuel firing is that oxy-fuel furnaces do not have a conventional combustion gas preheat system and so the capital cost is generally lower than for a regenerative or recuperative furnace of comparable pull-rate. In most applications, the determining factor regarding cost effectiveness of oxy-fuel firing will be the difference between the energy savings and the costs of the oxygen compared with the costs of alternative NO$_x$ abatement techniques.

Process: Oxygen-Enhanced Combustion Modifications

Development Status:

The coal-fired boiler technology needs to be demonstrated over several months to show effectiveness, reliability, and safety. Such a demonstration is expected to begin during the summer of 2003. The technologies are commercially available for application to cement and glass manufacturing.

Practical Considerations:

Using oxygen enrichment results in less flue gas flow since it eliminates the nitrogen in the air it replaces. The merits of oxy-fuel firing vary greatly from case to case depending on furnace size and availability of pure oxygen. The technique is most effectively installed during furnace rebuild. Hot installation may lead to energy savings and to an increased pull rate; however, it is unlikely to result in lower NO_x emissions, and there is a danger of accelerated refractory wear.

Furnace waste-gas temperature can be very high, 1200-1300 °C and will usually require cooling. Due to high water content and concentration of corrosive species, cooling is usually by dilution with air. The higher temperatures associated with the technique can result in higher refractory wear.

Many potential users do not want to own and operate an air-separation plant. Oxygen suppliers offer to build, own, and operate the air separation system in return for a long term contract for oxygen sales.

Compatibility with other air pollution control technologies:

Oxygen-enhanced combustion on coal-fired boilers can only be effective when implemented with OFA. If O_2 is added to an unstaged flame, NO_x emissions will increase. The technology can also be combined with SNCR or SCR for greater NO_x reductions. O_2 can also be used with post-combustion NO_x control technologies in cement kilns and glass melters.

Secondary Environmental Impacts:

Oxygen-enhanced combustion may lessen the impacts of staged combustion. The following are potential impacts that must be analyzed on an individual unit basis:

- CO may increase due to stoichiometry in the burner zone

- LOI may increase due to increased staging

- ESP performance may degrade with increased LOI or finer particulate.

Oxy-fuel firing can also help to reduce overall emissions of volatile materials from the kiln or furnace (particulates, fluorides, chlorides etc.), due to reduced gas flow and in some cases reduced turbulence.

- Particulate emissions in soda-lime glass can be reduced to 0.2-0.3 kg/ton.
- Particulate emissions most effectively reduced for boron containing glasses (up to 50%).
- Reduction in fuel usage leads to lower SO2 emissions for oil-fired furnaces.

Concentrations of all pollutants may actually be higher due to reduced gas volume, although the absolute emission is reduced. Dilution with cooling air usually brings the concentrations closer to more normal levels.

References:

U.S. Environmental Protection Agency, "Alternative Control Techniques Document: NO_x Emissions from

Process: Oxygen-Enhanced Combustion Modifications
Utility Boilers”. EPA Document No. EPA-453/R-94-023, July 1994. Bool, L., “NO_x Reduction from a 44MW Wall-Fired Boiler Utilizing Oxygen-enhanced Combustion”, EPRI/DOE/EPA Mega Symposium, Washington, May 2003

Process: Pre-Stratified Charge

Category	NO_x, TPY (WRAP 1996>100 TPY)	%NO_x reduction	Cost, $/ton	Status
Reciprocating Engines	86,210	80-95%	<500	Commercial

Process Description:

Air is injected into the intake manifold so that during the intake stroke, the piston initially draws in air, followed by a fuel-rich air-fuel mixture. Thus, the mixture near the spark plug is fuel rich, promoting good combustion, while the mixture away form the spark plug is very lean, acting a s a heat sink and suppressing NO_x formation.

NO_x Reduction:

From tests for ten engine models ranging from 100 to 800 bhp, NO_x emissions ranged from about 0.1 g/bhp-hr to 9.5 g/bhp-hr, with a mean of 0.6 g/bhp-hr. Engines ranging from 300 to 800 bhp averaged 95% reduction, while tests on engines less than 50 bhp showed NO_x reductions averaging 77%.

Vendors guarantee the achievable NO_x emission level of 2.0 g/bhp-hr.

Cost Information:

See EPA Report below.

Development Status:

Commercially available. In commercial use since 1980s.

Practical Considerations:

Applicable only to carbureted (i.e. non-fuel-injected) rich-burn engines. May cause some power derating; 20% has been observed. While the PSC system itself requires very little maintenance, the engines require more frequent overall maintenance.

Compatibility with other air pollution control technologies:

Compatible with exhaust gas recirculation (EGR), with air injected by PSC system coming form the engine’s exhaust. May also be used in conjunction with post-combustion technologies. However, the overall NO_x reductions are not strictly additive and careful evaluation is required to ensure cost effective strategies.

Secondary Environmental Impacts:

Possible increase in CO and VOC emissions.

References:

Edgerton, S. W., Lee-Greco, J., and Walsh, S. “Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques (Final Report).” EPA contract No. 68-D98-026, EC/R Incorporated, Chapel Hill, NC, August 29, 2000.

Process: SCONOx Technology

Category	NO_x, TPY (WRAP 1996>100 TPY)	%NO_x reduction	Cost, $/ton	Status
Reciprocating Engines	86,210	95%	Not available	Commercial
Oil/NG boilers	32,910	70-99%	Not available	Commercial
Turbines	25,278	>90%	>7,000	Commercial

Process Description:

The SCONOx system adds a chemical reactor for NO_x sorption using a catalyst/sorbent to remove NO_x, carbon monoxide, and VOC. NO_x is oxidized in the presence of a platinum-based catalyst and the resulting NO_2 is adsorbed onto a potassium carbonate sorbent, forming potassium nitrites. The sorbent must be regenerated periodically by passing a controlled mixture of regeneration gases across its surface in the absence of oxygen. Regeneration gases react with the nitrites to form water and elemental nitrogen. The system is installed as a bed of sorbent/catalyst. A system of louvers and piping allows portions of the bed to oxidize and adsorb pollutants and other portions of the bed to undergo regeneration.

NO_x Reduction:

The first commercial installation in gas turbines achieved NO_x emissions below 2 ppm, a reduction of over 90%.

Vendor testing shows SCONOx reduced NO_x emissions in natural gas-fired reciprocating engines up to 95%. Preliminary testing in diesel engines found the technology reduced NOx by 98.9% to 0.4 g/bhp-hr.

Cost Information:

Cost for Gas Turbine application is preliminary and from DOE reference below.

Development Status:

Commercially available

First commercial installations in gas turbines commenced in 1999. Commercial applications for natural gas-fired reciprocating engines went online in 2000. Diesel applications were sold in 2000, but further information is unavailable.

Practical Considerations:

The technology was initially applied only to gas turbines, but variations have been developed for natural-gas and diesel-fired reciprocating engines.

Regeneration gas flow is about 1 percent of exhaust gas flow. Typically, natural gas is converted to hydrogen in a reformer at 600-900 °F to produce the regeneration gas. The regeneration step is complicated and the reformer requires additional labor and maintenance.

Exhaust temperatures should be controlled at 600-700 °F for best NO_x reduction. Performance also improves as exhaust gas oxygen levels approach zero. Temperature and O_2 control may be difficult at some sites. The catalyst is de-activated by soot or sulfur species, so catalyst must be cleaned every 20,000 hours.

Process: SCONOx Technology

SCOSOx is required to remove SO_2, which would otherwise poison the SCONOx catalyst. SCOSOx requires regeneration similar to SCONOx.

Compatibility with other air pollution control technologies:

Due to the emerging nature of the technology, little is discussed about compatibility with other technologies. Based on tests with LEC engines, issues regarding increases in CO/VOC may be of concern

Secondary Environmental Impacts:

Carbon monoxide and VOC are also reduced up to 95%.

References:

Edgerton, S. W., Lee-Greco, J., and Walsh, S. “Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques (Final Report).” EPA contract No. 68-D98-026, EC/R Incorporated, Chapel Hill, NC, August 29, 2000.

Amar, K.P., Staudt, J. “Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines; Technologies and Cost Effectiveness.” Northeast States for Coordinated Air Use Management, Boston, MA, January, 2001.

Goal Line Environmental Technology News. “Cummins Engine Co. Tests SCONOx® for Diesel IC Engines.” Oct 1999. Vol 1, Issue 3.

Process: Selective Catalytic Reduction (SCR)

Category	NO_x, TPY (WRAP 1996>100 TPY)	%NO_x reduction	Cost, $/ton	Status
Coal-fired boilers	607,748	70-90%	1,500-2,000	Commercial
Reciprocating Engines	86,210	75-90%	<1,000	Commercial
Oil/NG boilers	32,910	70-90%	2,000-10,000	Commercial
Turbines	25,278	~90%	500-10,000	Commercial
Refinery Process Heaters	9,311	75-90%	3,700-11,000	Commercial
Glass Melters	5,033	75-90%	---	Commercial

Process Description:

Post-combustion NO_x controls include **Selective Non-Catalytic Reduction** (SNCR) and **Selective Catalytic Reduction** (SCR). They are fundamentally similar, in that both use an ammonia-containing reagent to react with the NO_x produced in the boiler, and convert it to harmless nitrogen and water, SNCR accomplishes this at higher temperatures (1700ºF-2000ºF) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 600ºF to 750°F) and hence needs a catalyst to produce the desired reaction between ammonia and NO_x. High temperature catalysts, sometimes used in gas turbine applications can operate at temperatures up to ~1100°F

Conventional SCR incorporates a reactor located typically between the economizer and the air preheater. The reactor housing is sized to provide optimum flue gas velocity and catalyst volume.

In about one-quarter to one-third of the German SCR installations, the SCR reactor is located downstream of the flue gas desulfurization (FGD) system. This is called a "tail-end" configuration. Because the catalyst operates at temperatures of at least 600+°F, the flue gas temperature needs to be increased between the FGD and tail-end SCR. This reheating the flue gas before it enters the SCR. This extra equipment makes the capital and energy costs higher than in a conventional SCR. On the other hand, the tail-end SCR uses less catalyst, experiences a longer catalyst life, and can be built without impacting plant operations, with tie-in typically occurring during a normal two-week outage.

An ammonia injection system is located upstream of the catalyst typically in a grid configuration to inject and disperse the ammonia uniformly into the flue gas.

NO_x Reduction:

NO_x reductions of 90+% are capable with SCR. NO_x reduction levels are typically limited by the need to control residual ammonia to low levels (2-5ppm), and by cost effectiveness considerations (higher cost-to-NOx reduction ratio for deeper reductions. SCR applications typically represent a balance between the percentage NOx reduction requirement, residual ammonia limit, SO_2 to SO_3 oxidation rate, and ability to continuously maintain a uniform, stable NH_3/NO_x distribution across the entry plane into the catalyst.

Cost Information:

Capital costs for retrofit SCR systems to power generation sources are mostly within the range of $60/kW to about $140/kW. The lower end of this range applies to retrofits with nominal difficulty. The high end of the range would typically be associated with retrofits having significantly impeded construction access, extensive relocations, and difficult ductwork transitions.

Process: Selective Catalytic Reduction (SCR)

Operating costs are mainly driven by cost of reagent, energy penalty (pressure loss, ammonia vaporization), catalyst replacement and dedicated O&M costs

Development Status:

Commercially available

SCR is widely used oversees (Germany and Japan represent over 50,000 MW of installed capacity. In the US, significant activity has recently occurred with SCR installations on coal fired units. Projections for over 100 new installations in the US in the next 5 years have been made.

Practical Considerations:

From a technical perspective, SCR can be used many different applications and sources. However, the cost can vary considerably depending on retrofit difficulty and plant layout, fuel, or unit operating characteristics.
The performance of an SCR system is dependent on the size and arrangement of the catalysts, the fuel burned, gas flow conditions at the catalyst entrance, and the type and amounts of reagent used. A number of factors should be considered when installing an SCR system. They include:

- Operating temperature window temperature which is a function of the catalyst formulation but typically ranges between 600°-750°F for sulfur bearing fuels,
- Ammonia injection system design to ensure good distribution in proportion to the mass flux of NO_x for optimized performance (maximum NO_x reduction and minimum NH_3 slip)
- Flue gas pressure drop which is dependent upon flue gas velocity, catalyst configuration, and quantity of catalyst required to achieve specified NO_x reduction
- Flue gas flow/temperature distribution, as catalyst guarantees are typically predicated upon predetermined conditions
- Fouling potential of catalyst and/or APH surfaces. Reaction of excess ammonia with SO_3 generated in the furnace when firing sulfur bearing fuels will form ammonium bisulfate/sulfate that deposits on the cold end sections of the air heater to cause corrosion and increased pressure drop
- Flue gas contaminants - alkaline compounds, halogens, and heavy metals can cause catalyst poisoning.
- Decreased heat rate at low load if economizer bypass is needed to maintain the required flue gas temperature in the SCR reactor.

Compatibility with other air pollution control technologies:

SCR applications are fully compatible with combustion NOx controls (LNBs, OFA, reburn, etc.) and can be used with other amine-based controls (e.g. SNCR) in hybrid configurations. In theory, most of these technologies can be used together. However, NO_x reductions are not necessarily additive, and more importantly, the “economics” of the combined technologies may or may not be cost-effective. Such analyses are highly site- and strategy-specific.

However, several such combinations of technology are considered attractive and have or are gaining acceptance. For example, the combination of LNB/OFA with either SCR or SNCR is more prevalent than the application of the post-combustion technologies alone. The economics of this approach are justified by the reduced chemical and capital costs due to lower NO_x levels entering the SCR system.

Process: Selective Catalytic Reduction (SCR)

When combining SCR with NO_x control technologies whose performance depends on mixing characteristics in the upper furnace (i.e., OFA, reburn, or SNCR), potential stratification of inlet NO_x levels to the SCR becomes a key design issue that can impact SCR performance.

Secondary Environmental Impacts:

Potential impacts arising from the application of SCR include:

- Increased corrosion downstream of the SCR from SO_3 formed on the catalysts
- Air heater fouling due to ammonia bisulfate formation in the cold end
- Ammonia contamination of fly ash affecting its salability or disposal
- Increased system pressure drop
- FGD waste management, if located downstream of SCR

These impacts are mostly relevant to applications with sulfur and other contaminants-bearing fuels (e.g. coal/oil). Applications with natural gas are more benign both with respect to catalyst choice and life, as well as other plant impacts.

References:

EPRI, “Retrofit NO_x Controls for Coal-Fired Utility Boilers – 2000 Update”, EPRI Final Report, December 2000

NESCAUM, “Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers”, June 1998.

Cichanowicz, J., “100 GW of SCR: Installation Status and Implications of Operating Performance on Compliance Strategies”, EPRI/DOE/EPA Mega Symposium, Washington, May 2003

McIlvaine, R., “SCR Operating Experience of German Power Plant Owners as Applied to Challenging US High Sulfur Service”, EPRI/DOE/EPA Mega Symposium, Washington, May 2003

Process: Selective Non-Catalytic Reduction (SNCR)				
Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Coal-fired boilers	607,748	25-50%	800-1,500	Commercial
Cement Kilns	41,009	30-70%	200-1,000	Commercial
Oil/NG boilers	32,910	30-60%	1,300-3,000	Commercial
Wood/Biomass boilers	9,776	40-80%	900-2,200	Commercial
Refinery Process Heaters	9,311	50-70%	1,200-2,700	Commercial
Glass Melters	5,033	~40%	---	Commercial

Process Description:

Post-combustion NO_x controls include **Selective Non-Catalytic Reduction** (SNCR) and **Selective Catalytic Reduction** (SCR). They are fundamentally similar, in that both use an ammonia-containing reagent to react with the NO_x produced in the boiler, and convert it to harmless nitrogen and water, SNCR accomplishes this at higher temperatures (1700ºF-2100ºF) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 600ºF to 750°F) and hence needs a catalyst to produce the desired reaction between ammonia and NO_x.

While this difference between the two technologies may seem minor, it yields significant difference in performance and costs. This is because in the case of SNCR, the reaction occurs in a somewhat uncontrolled fashion (e.g., the existing upper furnace becomes the “reactor”). In practice, this means that SNCR has lower capital costs (no need for a reactor/catalyst); higher operating costs (lower efficiency means that more reagent is needed to accomplish a given reduction in NO_x); and limited NO_x reduction capability (typically 30%-40%, with some cases achieving reductions in the 50% range).

With SNCR, the reagent is introduced directly into the upper furnace, within the temperature window above. Typical applications may include multiple injection nozzles at various elevations (temperature points). in the furnace to optimize the distribution of reagent as well as to allow for operation at various load points.

NO_x Reduction:

SNCR technology is typically capable of NO_x reductions in the range of 25% to 80% depending on many design and operating characteristics of the specific application.

Cost Information:

Capital cots range from $10 to $20/kW for power generation boilers.
Operating costs are driven primarily by the consumption of the chemical reagent – usually urea for SNCR - which in turn is dependent upon the efficiency of the as well as the initial NO_x level and the desired percent reduction. These are typically in the range of $500-$700/ton of NO_x.
An additional consideration important in the overall operating costs is the potential contamination of fly ash by ammonia making it potentially unsalable.

Development Status: Commercial
SNCR is a fully commercial technology widely employed in various industries and applications. Urea-based applications are the predominant approach, as urea seems to have several advantages over ammonia in large-scale applications.

Process: Selective Non-Catalytic Reduction (SNCR)

Practical Considerations:

SNCR applications must be considered on a site –specific basis as several design and operating characteristics will affect the suitability of the technology. Some key issues include

- Available temperature window
- Size (cross-section/height) of the furnace for appropriate distribution and mixing of the reagent
- Sulfur content of the fuel (SO_3 and NH_3 form ammonium salts which can have negative impacts on the downstream equipment)
- Operational profile of the unit (rapid swings in flows/temperatures often result in poor performance in terms of NO_x reduction and ammonia slip)

Compatibility with other air pollution control technologies:

SNCR applications are compatible with combustion NO_x controls (LNBs, OFA, reburn, etc.) and can be used with other amine-based controls (e.g. SCR) in hybrid configurations. In theory, most of these technologies can be used together. However, NO_x reductions are not necessarily additive, and more importantly, the “economics” of the combined technologies may or may not be cost-effective. Such analyses are highly site- and strategy-specific.

The application of SNCR with reburn has yielded several developments by different companies. Various approaches are available commercially. Essentially they all revolve around the ability to combine the injection the reburn fuel and the amine reagent in the upper furnace region. NO_x reductions are not additive but better than the individual technology. While these combined approaches have not gained extensive commercial deployment reductions of 60%-70% have been reported. Economic effectiveness needs to be properly addressed on an individual basis as both the cost of reagent and reburn fuel contribute to the overall cost analyses

Other variations of SNCR-based technology include the use of hydrocarbon injection to promote NH_3 reduction reactions, as well as reagent injection into a fuel rich zone of the OFA system. These variations while offered commercially are still under demonstration

Secondary Environmental Impacts:

SNCR has some of the same issues associated with SCR. The two most likely to warrant consideration are

- NH_3 slip (emissions and impacts on ash)
- Formation of nitrous oxide (N_2O – a green house gas). This is mostly associated with urea, as opposed to ammonia, and may become a larger concern from the perspective of global climate issues

References:

NESCAUM, “Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers”, June 1998.

EPRI, “Retrofit NOx Controls for Coal-Fired Utility Boilers – 2000 Update, Final Report”, December 2000.

Himes, R., “A Fresh Look at SNCR”, EPRI/DOE/EPA Mega Symposium, Washington, May 2003

EPRI, “Sate of the Art Assessment of SNCR Technology”, September 1993.

EPRI, “SNCR Feasibility and Economic Evaluation Guidelines for Fossil-Fired Utility Boilers”, May 1994

Process: Tempering (Water, air, steam injection)

Category	NO_x, TPY (WRAP 1996>100 TPY)	%NO_x reduction	Cost, $/ton	Status
Turbines	25,278	~50%	2,000-7,000	Commercial
Refinery Process Heaters	9,311	---	---	Commercial

Process Description:

Tempering is a combustion control using water, air, or steam to lower the combustion temperatures, which reduces thermal NO_x formation. Water or steam, treated to quality levels comparable to boiler feedwater, is injected into the combustor and acts as a heat sink to lower flame temperatures.

NO_x Reduction:

Controlled NO_x emission levels range form 25 to 42 ppmv for natural gas fuel and from 42 to 75 ppmv for distillate oil fuel.

Cost Information:

Capital costs for wet injection include a mixed bed demineralizer and reverse-osmosis water treatment system and an injection system. All costs are based on availability of the injection medium on site. Capital costs range from $388K for a 4,430 hp turbine ($89/hp) to $4,830K for a 216,000 hp turbine ($22/hp). For steam injection, capital costs are slightly higher than for water injection.

Development Status:

Commercially available

Practical Considerations:

This technique is available for all new turbine models and can be retrofitted to most existing installations. The decision of which injection medium to use for NO_x reduction depends on many factors including the availability of steam injection nozzles and controls from the turbine manufacturer, the availability and cost of steam at the site, and turbine performance and maintenance impacts. This decision is usually driven by site-specific environmental and economic factors.

Compatibility with other air pollution control technologies:

None.

Secondary Environmental Impacts:

None expected.

References:

Alternative Control Techniques Document: NO_x Emissions from Stationary Gas Turbines. EPA Document No. EPA-453/R-93-007, January 1993.

U.S. Environmental Protection Agency. “Alternative Control Techniques Document – NO_x Emissions form Stationary Reciprocating Internal Combustion Engines.” EPA-453/R-93-032, July, 1993.

Process: Tempering (Water, air, steam injection)
Poole, L., “Houston Galveston Area NO_x Abatement Industries Perspective,” present at the Council of Industrial Boiler Owners, NO_x Control XV Conference, Houston, TX, August 2002.

APPENDIX D: PM Control Technology Summaries

Process: Cyclones

Category	PM, TPY (WRAP 1996 >100 TPY)	%PM reduction	Cost	Status
Mineral Processing	24,499	50 – 90%	See below	Commercial
Petrochemical	10,836	50 – 90%	See below	Commercial
Wood/Biomass boilers	5,718	50 – 90%	See below	Commercial
Primary metal production	4,697	50 – 90%	See below	Commercial
Pulp & Paper	4,476	50 – 90%	See below	Commercial

Process Description:

Cyclones use centrifugal force to separate particulate from gas streams, and belong to the broader family of mechanical collectors, which use a variety of mechanical forces to collect particulate. A multiple cyclone is an array of a large number of small (several inch diameter) cyclones in parallel.

PM Reduction:

Multiple cyclones have overall mass removal efficiencies of 70-90%. However, cyclone collection efficiencies fall off rapidly with particle size, so that control of fine particulate (PM-2.5) is limited. While collection efficiency is a function of the cyclone design and particle properties, cyclone removal efficiencies will be 90% or greater for 10 micron particles, dropping to perhaps 70% for 2.5 micron particles, and 50% for 1 micron particles. Addition of a second multiple cyclone in series with the first will allow for increased removal efficiency.

The efficiency of a cyclone increases with the gas flow rate through the cyclone. Cyclones are therefore most effective at high boilers loads, where flue gas flow rates are highest, with collection efficiency decreasing at lower loads.

Cost Information:

The following values represent typical costs for several of these technologies (these numbers reflect unit sizes ranging from utility-size units up to about 2,000,000 ACFM to smaller process down to about 10,000 ACFM).

- Capital - $1 - $5/ACFM
- O&M - NA

Development Status:

Commercial.

Cyclones have been used extensively in various particulate collection applications over the years. In the past, industrial plants used mainly cyclones. Cyclones are robust technologies that can deal with the cyclic operation and load changes. However, their efficiency is moderate when compared with ESP or fabric filtration

Practical Considerations:

Cyclones are best suited for applications of relatively large particle sizes as their effectiveness on smaller particles is limited

Cyclones are less expensive than other PM controls and have no costs beyond the initial capital cost.

Process: Cyclones

Multiple cyclones have no moving parts, but do require regular cleaning to avoid plugging, and preventive maintenance to avoid leaks, which can disrupt flow patterns and thus lower collection efficiency.

Compatibility with other air pollution control technologies:

Cyclones are compatible with other PM controls and may be desirable in selected applications to minimize PM loadings into downstream controls such as an ESP, FF or PM scrubber

Secondary Environmental Impacts:

None expected.

References:

http://www.icac.org

http://www.IEA-coal.org.UK/

http://www.croll.com

Process: Electrostatic Precipitator (ESP)

Category	PM, TPY (WRAP 1996 >100 TPY)	%PM reduction	Cost	Status
Coal-fired boilers	46,010	90%-99+%	See below	Commercial
Wood/Biomass boilers	5,718	90%-99+%	See below	Commercial
Oil/NG boilers	1,379	90%-99+%	See below	Commercial
Cement kilns	641	90%-99+%	See below	Commercial

Process Description:

ESP's operate on the principle of electrophoresis, by imparting a charge to the particulates and collecting them on opposed charges plates. Dry vs. wet refers to whether the gas is water cooled and saturated prior to entering the charged plate area, or is collected dry on the plates.

Electrostatic precipitators (ESPs), have been in use for particulate control since the early 1920's, use electrical fields to remove particulate from boiler flue gas.

In an electrostatic precipitator, an electric field is maintained between high-voltage discharge electrodes, typically wires or rigid frames, and grounded collecting electrodes, typically plates. A corona discharge from the discharge electrodes ionizes the gas passing through the precipitator, and gas ions subsequently ionize particulates. The electric fields impart electrostatic forces to the negatively charged particles, "driving" them to the collecting electrodes. Particulates are collected from the electrode plates either by mechanical rapping (Dry ESP) or by using a water spray to remove this particulate. (Wet ESP).

In a typical electrostatic precipitator, collecting plates are arranged parallel to the gas flow, normally 9-18 inches apart, with discharge electrodes between them. Most precipitators have 3-5 independent electrical sections, i.e., sets of discharge and collecting electrodes with independent power supplies called Transformer/Rectifier (TR) sets, in series. Each independent section removes a fraction of the particulate in the gas stream. This arrangement allows the use of lower power (higher voltages, but lower current) in the first sections of the precipitator, where there is more particulate to be removed. Higher power is needed in the later sections, to collect the smaller particles.

A typical wet ESP configuration uses cylindrical collecting electrodes, with discharge electrodes located in the centers of the cylinders. Wet ESPs are useful in obtaining low opacities through the removal of acid gases and mists in addition to fine particulate. In addition, these devices have no rapping re-entrainment losses, and no back corona.

PM Reduction:

Many factors determine electrostatic precipitator removal efficiency. ESP size is an important one. Size determines residence time (longer particle residence times help collection efficiency)
Precipitator size is related to and usually referred to as the specific collection area (SCA), the ratio of the surface area of the collection electrodes to the gas flow. Higher collection areas lead to better removal efficiencies. Collection areas normally are in the range of 200-800 ft^2/1000 acfm. In order to achieve collection efficiencies of 99.5%, specific collection areas of 350-400 ft^2/1000 acfm are typically used.

Electrostatic precipitator collection efficiencies can exceed 99.9%, and efficiencies in excess of 99.5% are common. Precipitators with high overall collection efficiencies will have high collection efficiencies for particles of all sizes. Good control of PM-10 and PM-2.5 can be achieved with well-designed and operated electrostatic precipitators.

Process: Electrostatic Precipitator (ESP)

Precipitator collection efficiencies decreases for very small particles (less than 1 micron). The reason for lower efficiency for submicron particles is that both particle charge and the resistance of the gas to particle motion increase with particle size. As particles get smaller, the particle charge is lower, while the resistance to particle motion is higher resulting in poor collection. In practice this effect means that an ESP precipitator with a 99.9% overall mass collection efficiency may only collect over 90% of submicron particles, and over 97-98% of the 0 to 5 micron particles.

Some older precipitators on utility boilers are small, with SCAs below 200 ft^2/1000 acfm and correspondingly short treatment times.

Cost Information:

The following values represent typical costs for several of these technologies (these numbers reflect unit sizes ranging from utility-size units up to about 2,000,000 ACFM to smaller process down to about 10,000 ACFM))

- Capital: $15 - $40/ACFM
- Fixed O&M: Dry ESP’s - $0.25 - $0.65/yr-ACFM
  Wet ESP’s - $0.15- $0.50/yr-ACFM
- Variable O&M: Dry ESP’s - $0.45 - $0.60/yr-ACFM
  Wet ESP’s - $0.25 - $0.50/yr-ACFM

Development Status:

Commercial

ESP’s have been in use for over 75 years and are a widely recognized technology option for PM control

Practical Considerations:

Maximizing electric field strength will maximize precipitator collection efficiency.

Other actors limiting precipitator performance include flow non-uniformity and particle re-entrainment. Uniform flow distribution helps ensure that there are no high gas velocity, short treatment time paths through the precipitator.

Re-entrainment of collected particles may occur during rapping. Proper rapper design and timing will minimize rapper re-entrainment. Maintenance of appropriate hopper ash levels and of flow uniformity will minimize re-entrainment of ash from the hoppers.

A major consideration of ESP collection efficiency is the electrical resistivity of the particles to be collected. Particles with resistivities in the range of 10^7-10^{10} ohm-cm are more easily collected with ESPs: these particles are easy to charge, and loose their charge slowly once deposited on a collecting electrode. Particles with low resistivities (less than 10^7 ohm-cm), on the other hand, loose their charge to a collecting electrode rapidly and tend not to adhere to the electrode, causing high re-entrainment losses. (Carbon black is an example of a low resistivity material).

Particles with high resistivity (greater than 10^{10} ohm-cm) can be difficult to remove with a precipitator: such particles are not easily charged, and thus are not easily collected. High-resistivity particles also form ash layers with very high voltage gradients on the collecting electrodes. Electrical breakdowns in these ash layers lead to injection of positively charged ions into the space between the discharge and collecting

Process: Electrostatic Precipitator (ESP)

electrodes ("back corona"), thus reducing the charge on particles in this space and lowering collection efficiency. Fly ash from the combustion of low-sulfur coal typically has a high resistivity, and thus is difficult to collect. Flue gas treatment options exist to address both high and low resistivity problems and include the injection of ammonia, SO_3 and other proprietary additives.

Compatibility with other air pollution control technologies:

ESP’s are compatible with other PM controls and may be desirable in selected applications to minimize PM loadings into downstream controls such as a FF or PM scrubber

Secondary Environmental Impacts:

None expected.

References:

EPRI, “Economic Evaluation of Particulate Control Technologies”, Final Report, September 1992.

Staehle, R., “The Past, Present and Future of Wet ESPs in Power plant Applications”, EPRI/DOE/EPA Mega Symposium, Washington, May 2003.

IEA Coal Research, “Particulate control Handbook”, Final report, July 1997.

IEA Coal Research, “Prevention of Particulate Emissions”, Final report, December 2000.

ICAC, “ESPs vs. Fabric Filters: A Symposium and Debate”, March 1994.

http://www.icac.org

http://www.IEA-coal.org.UK/

http://www.croll.com

Process: Fabric Filter				
Category	**PM, TPY (WRAP 1996 >100 TPY)**	**%PM reduction**	**Cost,**	**Status**
Coal-fired boilers	46,010	99+%	See below	Commercial
Mineral Processing	24,499	99+%	See below	Commercial
Wood/Biomass boilers	5,718	99+%	See below	Commercial
Fugitive	5,631	99+%	See below	Commercial
Oil/NG boilers	1,379	99+%	See below	Commercial
Cement kilns	641	99+%	See below	Commercial

Process Description:

Fabric filter (FF) collectors (also referred to as baghouses) are the industrial equivalent of very large vacuum cleaners: by passing flue gas through a tightly woven fabric, particulate in the flue gas will be collected on the fabric by sieving and other mechanisms. The dust cake which forms on the filter from the collected particulate can contribute significantly to the overall collection efficiency.

FF types are usually defined by the type of bag cleaning utilized. Major types include: (1) the "reverse-air" baghouse, where the flue gas flows upward through the insides of vertical bags, which open downward. The fly ash thus collects on the insides of the bags, and the gas flow keeps the bags inflated. To clean the bags, a compartment of the FF is taken off-line, and the gas flow is reversed. This causes the bags to collapse, and collected dust to fall from the bags into hoppers. (Shaking or other method may be necessary to dislodge the dust from the bags.); and (2) the pulse-jet fabric filter, where the dirty gas flows from the outside of the bags inward, and the bags are mounted on cages to keep them from collapsing. Dust that collects on the outsides of the bags is removed by a reverse pulse of high-pressure air. This cleaning does not require isolation of the bags from the flue gas flow, and thus may be done on-line.

PM Reduction:

FF's are capable of 99.9% removal efficiencies. In addition removal efficiency is relatively level across the particle size range, making FF's good alternatives for very small particle sizes

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Key performance factors include the fabric of the bag, the cleaning frequency and methods, and the particulate characteristics. Fabrics can be chosen for different applications, and some fabrics are specialty-coated for enhanced removal of submicron particulate.

Cleaning intensity and frequency are also important variables in determining removal efficiency. Because the dust cake can provide a significant fraction of the fine particulate removal capability of a fabric, cleaning which is too frequent or too intense will lower the removal efficiency. On the other hand, if removal is too infrequent or too ineffective, then pressure drop will increase rapidly and impact overall operation.

Process: Fabric Filter

Cost Information:

FF’s have been used extensively for many years in different industries. The power generation sector while predominantly dominated by ESP’s has started to utilize FF’s in the last 20 years.

- Capital: Reverse Air Fabric Filter - $17 - $40/ACFM
  Pulse Jet Fabric Filter - $12 - $40/ACFM
- Fixed O&M: Reverse Air Fabric Filter - $0.35 - $0.75/yr-ACFM
  Pulse Jet Fabric Filter - $0.50 - $0.90/yr-ACFM
- Variable O&M: Reverse Air Fabric Filter - $0.70 - $0.80/yr-ACFM
  Pulse Jet Fabric Filter - $.90 - $1.1/yr-ACFM

Development Status:

Commercial.

FF’s have been used extensively for many years in different industries. The power generation sector while predominantly dominated by ESP’s has started to utilize FF’s in the last 20 years.

Practical Considerations:

FF size is determined by the choice of air-to-cloth ratio (A/C), or the ratio of air flow to cloth area, typically expressed in feet per minute (cubic feet per minute of flow divided by square feet of fabric area). The selection of air-to-cloth ratio depends on the particulate loading and characteristics, and the cleaning method used. A high particulate loadings will require the use of a larger FF (lower A/C) in order to avoid forming too heavy a dust cake, resulting in an excessive pressure drop

Pulse-jet FF’s are smaller (higher A/C) than reverse-air FFs due to the higher cleaning intensity and resulting bags being cleaner

Compatibility with other air pollution control technologies:

FF’s are compatible with other PM controls. FF’s are also choices for applications downstream of dry SO2 controls (e.g. spray dryers) as well as in combination with sorbent injection techniques for SO2 and/or Hg control

Adding a FF downstream from an existing electrostatic precipitator is a strategy gaining some acceptance in the power industry. Because the ESP removes the bulk of the particulate, the baghouse can be relatively small, and thus less expensive. One commercial approach to this is the installation of a small pulse-jet fabric filter downstream of an ESP, known as a Compact Hybrid Particulate Collector (COHPAC). Physically, it may be separate from the precipitator, or even fully integrated into the last field of the existing ESP, further reducing the over cost and space requirements.

Secondary Environmental Impacts:

As mentioned above FF’s can represent a complementary option to sorbent injection technologies where they enhance the contact (reaction) times between the sorbent and the flue gas contaminant of interest. This results in enhanced collection efficiency for the pollutant (e.g. mercury), as well as reduced quantities of sorbent needed

Process: Fabric Filter

References:

EPRI, “Economic Evaluation of Particulate Control Technologies”, Final Report, September 1992.

Staehle, R., “Particulate Control Options for Dry FGD Systems”, EPRI/DOE/EPA Mega Symposium, Washington, May 2003.

IEA Coal Research, “Particulate control Handbook”, Final report, July 1997.

IEA Coal Research, “Prevention of Particulate Emissions”, Final report, December 2000.

ICAC, “ESPs vs. Fabric Filters: A Symposium and Debate”, March 1994.

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http://www.croll.com

Process: PM Scrubber				
Category	**PM, TPY (WRAP 1996 >100 TPY)**	**%PM reduction**	**Cost,**	**Status**
Mineral Processing	24,499	50%-99+%	See below	Commercial
Petrochemical	10,836	50%-99+%	See below	Commercial
Wood/Biomass boilers	5,718	50%-99+%	See below	Commercial
Primary Metal production	4,476	50%-99+%	See below	Commercial
Pulp & Paper	4,476	50%-99+%	See below	Commercial

Process Description:

Scrubbers work on the principle of rapid mixing and impingement of the particulate with the liquid droplets and subsequent removal with the liquid waste. For particulate controls the "venturi scrubber" is an effective technology whose performance is directly related to the pressure loss across the venturi section of the scrubber.

Venturi scrubbers are one type of the more commonly used "scrubbers" for particulate collection. As the name implies, the scrubbing liquid and flue gases accelerate through a converging section into a narrow throat. In the throat, very high gas velocity shears the scrubbing liquid into many very fine droplets, which collect particles through numerous "collisions".

PM Reduction:

Scrubbers have varying PM reduction capabilities based on deign operating conditions and particle characteristics. Performance can range 50% for the small size fraction (< 2microns) to over 99% for the larger sizes.

Higher collecting efficiencies and a wider range of particulate sizes, require higher operating pressures. . High-energy scrubbers refer to designs operating at pressure drop of 50-70 inches of water. Of course, higher pressure translates to higher energy consumption.

Cost Information:

The following values represent typical costs for several of these technologies (these numbers reflect unit sizes ranging from utility-size units up to about 2,000,000 ACFM to smaller process down to about 10,000 ACFM)

- Capital: Venturi Scrubber - $5 - $20/ACFM
- Fixed O&M: Venturi Scrubber - $0.25 - $0.65/yr-ACFM
- Variable O&M: Venturi Scrubber - $1.2 - $1.8/yr-ACFM

Development Status:

Commercial

Wet scrubbers are widely used in various industries. One advantage of scrubbers is their ability to treat wet gases which are not conducive to other technologies such as dry ESPs and FFs.

Practical Considerations:

For applications where variation in flow require throat velocity compensation to maintain specified scrubbing efficiencies, automatic and manually variable throat designs are available.

Process: PM Scrubber

The automatic throat is used where flow conditions vary widely and frequent adjustments are required. When occasional variations occur, a manually controlled throat is generally sufficient.

Compatibility with other air pollution control technologies:

Scrubbers are compatible with other PM controls. However, dry ESP’s and FF’s would not be deployed downstream of a scrubber without prior reheating of the flue gas which would make such application economically questionable in general

Secondary Environmental Impacts:

Liquid waste disposal requires consideration on a case-by-case basis.

Since scrubbers have the capability to reduce acid gases, applications where this is important must be considered.

References:

IEA Coal Research, “Particulate control Handbook”, Final report, July 1997.

http://www.icac.org

http://www.IEA-coal.org.UK/

http://www.croll.com