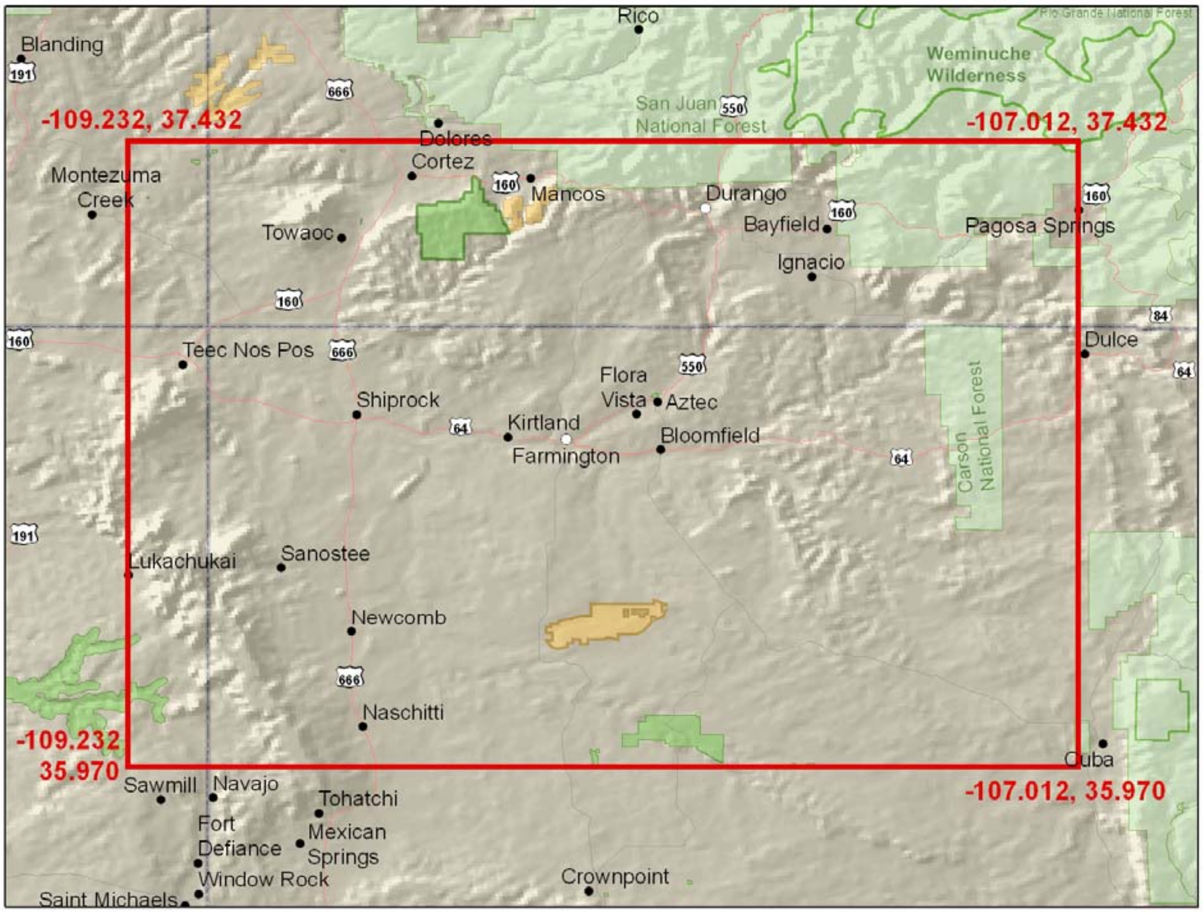
Four Corners Air Quality Task Force
Report of Mitigation Options



November 1, 2007

The report is a compilation of mitigation options drafted by members of the Four Corners Air Quality Task Force. This is not a document to be endorsed by the agencies involved, but rather, a compendium of options for consideration following completion of the Task Force's work in November 2007.

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Task Force members were those individuals who regularly attended quarterly meetings, participated in one or more work groups, and who assisted in drafting and providing comments on the mitigation option papers and other sections of the Task Force Report.

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Interested Parties were those individuals who followed the progress of the Task Force, and who may have attended one or more quarterly meetings, may have participated in work groups and may have provided comments on sections of the Task Force Report.

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Background and Purpose

Overview

The states of Colorado and New Mexico convened the Four Corners Air Quality Task Force (Task Force) in November 2005 to address air quality issues in the Four Corners region and consider options for mitigation of air pollution. The Task Force is comprised of more than 100 members and 150 interested parties representing a wide range of perspectives on air quality in the Four Corners. Members include private citizens, representatives from public interest groups, universities, industry, and federal, state, tribal and local governments.

This report represents a two-year effort of the Task Force and is a compendium of options to address air quality concerns in the Four Corners. This report is the result of hundreds of hours of time volunteered by Task Force members. The report's contents should not be construed as the conclusive findings or consensus-based recommendations of all Task Force members, but rather as an expression of the range of possibilities developed by this diverse group. This report provides a unique and invaluable resource for the agencies responsible for air quality management in the Four Corners area.

Air Quality Background

The Four Corners area is home to more than 400,000 people in 10 counties. Beautiful landscapes, rich history and cultural heritage, and numerous outdoor activity opportunities drive a significant tourism industry. The area is also home to an extensive energy development sector that is experiencing unprecedented growth. Furthermore, population and urbanization is increasing in the area. Increases in industrial development and population generally bring increases in air pollution. Good air quality is important to both residents and visitors in the Four Corners area, and immediate attention to this resource is necessary to ensure its protection.

The Clean Air Act sets forth a variety of air quality standards and goals. For example, the U.S. Environmental Protection Agency (EPA) sets National Ambient Air Quality Standards for the most prevalent pollutants that are considered harmful to public health and the environment. The EPA, states, and some tribes are responsible for keeping clean areas clean under the Clean Air Act's Prevention of Significant Deterioration program. In fact, the Four Corners area air quality is potentially subject to the requirements of four states, numerous tribes, EPA and Federal Land Managers. This jurisdictional array was a primary driver for the need for this task force.

The Prevention of Significant Deterioration program requires regulatory agencies to determine whether air pollution is causing adverse impacts to water, vegetation, soils and visibility in our National Parks and Wilderness areas. The states are currently working on plans to improve visibility as required by the federal Regional Haze Rule.

One pollutant that has been decreasing across the west is sulfur dioxide. However, ozone, nitrates (formed from Oxides of Nitrogen) and particulate matter are of particular concern in the Four Corners region due to increased oil and gas operations, power plants, and general growth. This area has not exceeded the federal health standards for these pollutants, but air monitoring in the region has shown that concentrations are approaching federal ambient air quality standards for ozone. Regulatory agencies are working to ensure that pollutant levels in the Four Corners region remain below the federal air quality standards. These same pollutants also impair visibility—hindering the ability of an observer to see landscape features—and affect other sensitive resources such as water quality and ecosystems in the region. Views in the Four Corners area are routinely impaired by air pollution.

Another pollutant of concern in the Four Corners region is mercury. Mercury is a naturally occurring metal that is released into the environment from industrial operations and household waste, including coal-fired power plants, crematoria, disposal of common household products and equipment, and mining. Mercury builds up and remains in the ecosystem and can be found in toxic levels in fish in many areas. The EPA promulgated the Clean Air Mercury Rule in 2005 to permanently limit and reduce mercury emissions from coal-fired power plants through the year 2018. States are currently working to implement this program.

Four Corners Air Quality Task Force

The agencies responsible for managing air quality in the Four Corners include the four states (Arizona, Colorado, New Mexico and Utah), the federal agencies (EPA, the U.S. Department of the Interior's Bureau of Land Management and National Park Service; the U.S. Department of Agriculture's Forest Service), and the tribal governments (Navajo Nation Environmental Protection Agency, Ute Mountain Ute, Jicarilla Apache and the Southern Ute Indian Tribe's Air Quality Department). These agencies are addressing the air quality issues discussed above, and believe the input of the residents, representatives of industry and environmental groups is important in developing effective air management strategies. The EPA, BLM, state agencies and some tribes have authority to control sources of air pollution.

In 2004, these agencies decided to work together to explore collaborative ways to manage air quality in the Four Corners area. The agencies agreed that an organized and sustained public process would be beneficial to developing meaningful air quality management strategies for the area. In November 2005, the states of New Mexico and Colorado officially convened the Four Corners Air Quality Task Force (Task Force).

The purpose of the Task Force was to bring together a diverse group of interested parties from the area to learn about and discuss the range of air quality issues and options for improving air quality in the Four Corners area. It was decided at the outset that the Task Force would be a process completely open to anyone with an interest in air quality issues in the Four Corners area. This meant that member participation fluctuated from meeting to meeting, although no meeting had fewer than 65 attendees and Task Force participation in total reached some 250 individuals (Task Force members and interested parties combined).

Initial work of the Task Force has already resulted in the implementation of one "interim" recommendation: the Bureau of Land Management has required new and replacement internal combustion gas field engines of between 40 and 300 horsepower to emit no more than two grams of nitrogen oxides per horsepower-hour; and, in Colorado, all new and replacement engines greater than 300 horsepower must not emit more than one gram of NOx per horsepower-hour. In New Mexico, all new and replacement engines greater than 300 horsepower must not emit more than 1.5 grams of NOx per horsepower-hour. These requirements apply to oil and gas development within the Bureau of Land Management's jurisdiction.

The Task Force Process

A process was developed that would easily accommodate new members throughout the two-year time period, but provided enough continuity so that a work product could be developed. The Task Force was divided into five working teams: three "source" groups: Power Plants, Oil and Gas, and Other Sources; and two "technical" groups: Cumulative Effects and Monitoring. The purpose of the work groups was to exchange ideas and information, discuss mitigation options, receive input, and coordinate the development of the mitigation options relating to those sectors. The technical work groups coordinated existing data and analyses that could inform the work of the Task Force, as well as identified additional air quality analyses and monitoring that may be helpful to the responsible agencies in developing air quality management plans.

The Task Force met face-to-face on a quarterly basis from November 2005 through November 2007. These meetings took place in Farmington, New Mexico and Durango and Cortez, Colorado. Additional work was carried on between meetings via conference call, and some smaller group meetings were held as needed. The website developed for the Task Force was the primary vehicle of on-going communications with Task Force members, and was hosted by the State of New Mexico at: http://www.nmenv.state.nm.us/aqb/4C/index.html. The website aided in the Task Force being an open forum for the exchange of ideas, as well as an educative tool, resource and bulletin board for Task Force members, interested parties and others.

Participants in the Task Force drafted mitigation ideas throughout the process following a simple format to promote consistency. Participants could also provide written input at any time, which was incorporated into the document on an on-going basis. Since it was not the intention of the Task Force for all members to come to consensus, the convention of a "Differing Opinion" was used so that individual members could share views that contrasted with what the author(s) had written. These appear throughout the report with the words "Differing Opinion" in bold print followed by the commenter's language.

In addition to Task Force member on-going input, the process included a public review period that enabled any interested individual (including Task Force members) to review and comment on the document. These comments were then reviewed by Task Force members, and revisions were made as members deemed appropriate. The public review comments are appended to each work group section of this document.

The Four Corners Air Quality Task Force implementation was mainly funded by grants from the states of New Mexico and Colorado; the U.S. Department of Interior, Bureau of Land Management and National Park Service; the U.S. Department of Agriculture, Forest Service, and the U.S. Environmental Protection Agency. In addition, many citizens, private corporations, non-profit organizations and other agencies provided in-kind support as well as resources to advance the work of the Task Force.

The Task Force Report

The Task Force Report is comprised of more than 125 mitigation options written by Task Force members and is the product of their work together over the two year period. These options describe possible strategies for minimizing air pollution impacts in the Four Corners area. These options are organized by source sector: Oil and Gas, Power Plants, and Other Sources, with an additional section on Energy Efficiency, Renewable Energy and Conservation that addresses all sources. Each group first brainstormed a broad spectrum of possible mitigation options and then decided on which options would be drafted into mitigation option papers. Those options that were not drafted are included in the Table of Mitigation Options Not Written with the group's rationale for not including them as written papers in this document.

There are also two technical sections: one on monitoring that discusses analysis gaps and offers ideas for improved monitoring in the area, and one on cumulative effects that provides some quantified estimates of emission reductions for some of the options, as well as ideas for additional analysis. Ideally, each option would have included an analysis regarding quantified air quality and other environmental, economic and other costs and benefits, as well as the costs to implement. Such analyses can be extremely resource and time-intensive and as such, could not be included for all options, but was included in options as available.

The Path Forward

This report will be considered by the federal, state, tribal and local agencies as they develop air quality and land management strategies, which may include developing new and revising existing regulations, supporting new legislation, developing new outreach and information programs, and developing and/or expanding voluntary programs for emission reductions. For instance, states may pursue some mitigation strategies as they develop strategies to enact specific, mandatory programs such as Regional Haze. The Bureau of Land Management may use options such as permit requirements for energy production. Industries may voluntarily practice a mitigation strategy to avoid further regulation.

This work of implementation will be done cooperatively among all of the agencies when appropriate, and individually as needed. Some of this work will include additional analyses of incentives for voluntary programs, air quality modeling, economic analyses, feasibility studies, and review of additional monitoring data. To enact new regulations, every jurisdiction requires a different level of analysis be performed, so there may be varying levels of study on any given option that a regulatory agency decides to pursue. The analyses and recommendations of the Cumulative Effects and Monitoring work groups will inform these agency processes.

Conclusion

An initial goal expressed at the first Task Force meeting was for greater awareness and understanding of air quality issues among the residents of the Four Corners area. In the end, the Task Force provided a unique forum for learning, the exchange of ideas and information, and a venue for all people in the area with interest in air quality to get to know one another. The result is a better informed and cohesive group of individuals who can speak to and support air quality management in the Four Corners area. The group became so cohesive that it was decided to reconvene the Task Force in approximately six months time to review progress made from the date of the Task Force Report's completion.

The work of the Task Force represents an invaluable resource to the agencies responsible for air quality management in the Four Corners area, and also for the general public as air quality management planning moves forward. The Task Force Report and process provides a model for other areas with similar concerns.

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Oil and Gas

Oil and Gas: Preface

Overview

The Oil & Gas Work Group of the Four Corners Air Quality Task Force was tasked with analyzing emission mitigation strategies for this industrial sector. For each Mitigation Strategy, and to the extent practicable, the Work Group documented the description of each strategy as well as implementation and feasibility considerations.

Participation in the Oil and Gas Work Group involved state, local and tribal air quality agencies, federal land management agencies, industry representatives, public citizens, and representatives of environmental organizations. Over six working sessions and many monthly conference calls, the work group identified more than 75 potential mitigation strategies. These mitigation strategies were then discussed and either drafted as a mitigation option paper, or eliminated from further analysis where a rationale to do so existed (see Table at the end of this document). The vast majority of the options discussed are represented herein by mitigation option papers for a total of 51.

Organization

The Oil and Gas industry is generally divided into sub-sections according to process. The Work Group used this progression in process to address each stage of the industry, with the exception of exploring Mitigation Options for Engines as a unique section that applies across the processes in the industry. For the purposes of organization and analysis of available Mitigation Strategies, the Oil and Gas portion of the TF Draft Report follows the sequence of definitions as identified below:

1. **Engines:** The work group addressed engines as a separate category in its analysis attributable to all processes in the oil and gas industry. The mitigation strategies were created to address the subcategories of stationary or mobile/non-road engines, drill rig engines, and turbines.
2. **Exploration & Production (E & P):** the work group defined E & P as the upstream sector of the oil and gas industry, including all activities associated with drilling, completion, and putting the well on-line. The work group identified and developed mitigation strategies for specific equipment in E&P, including oil/condensate tanks, dehydrators/separators/heaters, fugitive emissions associated with pneumatic operations, completions, and wellhead considerations.
3. **Midstream:** the work group defined Midstream Operations as occurring after custody transfer, including facilities such as compressor stations, gas processing plants, and transmission or storage of natural gas. Where appropriate, the work group devised mitigation strategies that avoided general overlap with E & P options, and concentrated primarily on options unique to the "midstream operations" that were not otherwise examined in the context of E&P operations.

The Work Group also identified and developed mitigation strategies that address **Overarching** and **Energy Efficiency and Renewable Energy** appropriate for consideration of application to the oil and gas industry.

ENGINES: STATIONARY RICE

Mitigation Option: Industry Collaboration

I. Description of the mitigation option

Overview

- This option explores the possibility of industry collaboration with engine manufacturers to achieve and reliably maintain emissions at or below prescribed levels for upcoming emission standards (i.e., NSPS for engines) on new engines. Such technologies could include but are not limited to lean burn or non-selective catalytic converters (NSCR) with air-to-fuel ratio controllers. The focus on such an effort would be on natural gas fired engines site rated at less than 300 hp.

Air Quality and Environmental Benefits

- This option would result in air quality improvement since all new engines built would meet lowest achievable emission controls at that time for criteria pollutants.
- **Differing opinion**: Reasonably available control technology is the accepted term used by EPA, industry, and regulatory entities versus lowest achievable emission controls that have a different connotation.

Economic

New Engines:

- Depending on the final emission levels established through this effort, operators might have to spend resources ensuring that prescribed emissions limits are being maintained.
- If through this option emission levels are set at levels lower than upcoming federal standards, then detailed engineering/economic analyses should be conducted to examine the incremental cost to control (over the federal regulatory baseline) and to determine if such additional controls are consistent with other programs.

Existing Engines:

- If such a program were expanded to include the retrofitting of all existing engines with current emission control technology, this would require a large capital investment from companies to achieve this result. This would result in replacement of older compressor engines, particularly those less than 200 hp,
- **Differing Opinion:** new engines would be a significant cost to the oil and gas industry. The salvage value of older compressors is a fraction of the cost of a new compressor engine.
- It would require companies to commit to ordering new engines over a prescribed time, likely ahead of when older units would have been replaced.
- The manufacturers would need confirmed orders to justify re-tooling their plants to meet the demand.

Trade-offs

- The use of given emission control technology could result in other emissions. For example, the use of lean-burn technology on a large scale would result in incremental emissions of formaldehyde. If NSCR is used on a large scale, it is believed ammonia emissions would result. However, it is not known if these emissions would be significant.
- Some engine manufacturers that cannot meet the demand and/or re-tool their factories could lose their market share in the San Juan Basin. Need to ensure this does not create any restraint of trade concerns.

II. Description of how to implement

A. Mandatory or voluntary: It could be both. The companies could begin a process of placing new orders voluntarily or the agencies, through regulatory/rules, could require emission levels that necessitate ordering new compressor engines.
Differing opinion: If this is industry collaboration with engine manufacturers, then the regulatory agencies should not expand to rule making that has requirements more stringent than NSPS.

B. Indicate the most appropriate agency(ies) to implement: State Environmental Agencies.
Differing opinion: Not appropriate. If this is industry collaboration with engine manufacturers, then the regulatory agencies should not expand to rule making that has requirements more stringent than NSPS.

III. Feasibility of the option

A. Technical: None identified although some field trials and bench scale tests are probably necessary to assess actual emissions on the new engines.
Differing opinion: EPA has assessed the technological feasibility of controlling these types of engines (See NSPS Mitigation Option Paper below.)

B. Environmental: Yes, from the Cumulative Effects group depending upon what type of emission control technology is preferred. The control technology that will be used will be based on the emission level selected, the lowest cost method of achieving the desired level of emission reduction and the reliability of maintaining emissions at the desired level. Ultimate decisions regarding control options should be based on measurable improvements in ambient air quality.

C. Economic: Economic burdens associated with engine replacement and manufacturer re-tooling are likely to be substantial.

IV. Background data and assumptions used

Emission inventories compiled for the Farmington, NM BLM Resource Management Plan (2003) and Southern Ute Indian Reservation Oil and Gas Environmental Impact Statement (2002).

- Preliminary discussions with companies and engine manufacturer representatives.
- Will need to integrate any more recent emissions inventory data from the Cumulative Effects Group.

V. Any uncertainty associated with the option (Low, Medium, High)

High, especially pertaining to economic feasibility and availability of field proven engines. High due to economics of replacing a large fleet of existing compressor engines and the timing that would be required to begin manufacturing a number of small horsepower engines.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

May need to verify with other work groups if manufacturing a large number of new compressor engines, particularly in the smaller horsepower range, could conflict with other new engine initiatives such as building Tier II and Tier III diesel engines and meeting requirements for additional NSPS general regulations.

Mitigation Option: Install Electric Compression

I. Description of the mitigation option

Overview

- Electric Driven Compression would involve the replacement or retrofit of existing internal combustion engines or proposed new engines with electric motors. Retrofit of internal combustion engines with electric drivers is not generally feasible. Not all compressors can be fitted with an electric motor. This normally requires either a complete package change or, at very least, gear modifications. Electric motors would be designed to deliver equal horsepower to that of internal combustion engines. However, the electric grid capacity in any given area may limit the size/number of electric engines potentially supportable. The reliability of the grid and the easements also must be considered.

Air Quality/Environmental

- Elimination of local emissions of criteria pollutants that occur with the combustion of hydrocarbon fuels (natural gas, diesel, gasoline). Displacement of emissions to power generating sources (utilities) primarily from coal fired power plants (with higher emissions than natural gas fired engines) or natural gas fired peaking units.
- The "emissions balance" for switching to 4-corners grid electricity is illustrated in the table directly below. As apparent, the switch is not necessarily positive when compared with "modern" gas-fired reciprocating engines. The actual "balance" would depend on the particular engine model being compared to an electrical option.

4 Corners Grid Average Emissions lbs/MWh (From NRDC Database) (Average of PNM, Xcel, and Tri-State)	
SO_2	3.4
NOx	3.8
CO_2	2,473
Caterpillar 3608 LE Average Emissions lbs/MWh (equivalent)	
SO_2	0
NOx	2.9
CO_2	1,138
Cat. 3608 Assumptions: 9815 Btu/kw-hr "Sweet" Natural Gas NOx - 1 g/hp-hr 1 cu ft gas = 1,000 btu	

See also Cumulative Effects Analysis for this option for further emissions analysis.

Economics

- The costs to replace natural gas fired compressor *engines* with electric motors would be costly. Not all natural gas fired compressors can be fitted directly with an electric motor. This normally requires a complete package change or at very least, gear modifications.

- The costs of getting electrical power to the sites would be extremely high in most cases. It could require a grid pattern upgrade, which could costs millions of dollars for a given area. Maintenance and repair costs associated with the electrical power source are not included.
- A routine connection to a grid with adequate capacity for a small electric motor can be $18K to $25K/site on the Colorado side of the San Juan Basin.
- A scaled down substation for electrification of a central compression site can range between $250K and $400K.
- Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small.

<u>Tradeoffs</u>

- While the sites where the electrical motors would be placed would not be sources of emissions, indirect emissions from the facilities generating the electricity would still occur such as coal-fired power plants.
- Additional co-generation facilities would likely have to be built in the region to supply the amount of electrical power needed for this option. This would result in additional emissions of criteria pollutants from the combustion of natural gas for turbines typically used for co-generation facilities. Co-generation produces both power and steam; as there is not a market for the steam, this might just be a need for additional power plants or combined cycle plants. Lead time and cost for permitting and new base load generating facilities could be substantial.
- There would need to be possible upgrades in the electrical distribution system. However, the limitation of doing so is predicated by the electrical grid that would exist in a given area to provide the necessary capacity to support electrical compression.
- When comparing emissions from electric generating facilities used to power electric compressors versus natural gas fired compressors, differences in emission rates as well as overall energy efficiency must be examined.

Burdens

- The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry. Extensive capital investments could be required if new generating facilities are needed to meet the electrical demand of this option.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary based on economics of meeting emission reduction requirements and/or initiatives and feasibility of implementation.

B. Indicate the most appropriate agency(ies) to implement: No agency action needed to implement a voluntary program.

III. Feasibility of the option

A. Technical: Feasible depending upon the electrical grid in a given geographic area and overall available electrical power for large-scale conversion in a given geographic area.

B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Indirect emission implications for grid suppliers should be considered (e.g., coal-fired plants).

C. Economic: The economics of implementing this option are much larger than stated above. Considerations such as (but not limited to): 1) cost of energy; 2) electrical demand; 3)reliability; and 4) efficiency need to be included in such an analysis. Costs to control calculations are needed to determine if they are consistent with other options being considered. Modeling needs to be conducted to evaluate if potentially shifting emissions from natural gas to coal would result in ambient air quality benefits.

IV. Background data and assumptions used

The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff.

V. Any uncertainty associated with the option (Low, Medium, High):

HIGH to MEDIUM based on land accessibility (easements), electric source availability and reliability of uninterrupted supply, advancing GHG legislation/regulation, and economics.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups:

Possibly the Cumulative Effects Group due to indirect emission increases from coal-fired plants. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Install Electric Compression (Alternative - Onsite Generators)

I. Description of the mitigation option

Overview

As an alternative to grid power dedicated on-site natural gas-fired electrical generators can be used to supply power to electric motors that replace the selected RICE compression engines. The electric motors would be rated at an equivalent horsepower to that of RICE engines currently used for gas compression. The power sources for the electric compression could consist of a network of on-site gas-fired electrical power generators. The alternative could be expanded to include consideration of replacement of other engines, such as, gas-fired pump-jack engines used as "prime-movers."

The currently available gas electric generator run on variety of fuels including low fuel landfill gas or bio-gas, pipeline natural and field gases. The gas electric generators are available in the power rating from 11 kW to 4,900 kW. Decisions on the use of on-site generators to replace natural gas-fired engines and the number of generators required would depend on a number of factors, including the proximity, spacing and size of existing engines. As a simple example using the conversion factor of 1 MW = 1,341 HP, adding a 1 MW natural gas-fired generator could replace an inventory of approximately 33 small (40 hp) internal combustion engines if these were reasonably close proximity, say spaced within a one or two mile radius. However, in "real world" operations, there will be several factors involved in determining the number of required gas-fired electrical generators; such as transmission loss, ambient operating temperature, load operating conditions, pattering of applied loads, etc.

Air Quality/Environmental Benefits

The emissions from gas electrical generators are relatively low compare to smaller internal combustion engines because of new technology and ability of controlling emission from big engines. For example a Caterpillar G3612 gas electrical generator with power rating of 2275 kW emits 0.7 gram/hp-hr NOx at 900 rpm, which is equivalent to 0.0009387 g/W-hr. For comparative illustration with alternative 1, if you assume …. As stated in the mitigation option; "Control Technology Options for Four Corners Power Plant" (FCPP), the NOx emission from FCPP is approximately 0.54 g/mmBtu. Based on the assumption that efficiency of FCPP is 40%, the NOx emission from FCPP is approximately 0.002099 g/W-hr. This comparison shows that the gas electrical generator is more environmentally friendly then using power from a coal based power plant. The baseline average emission for the Western Grid should be used to calculate the real emission difference between installing a lean burn electric generator to replace combustion engines.

The noise from continuously running internal combustion engines can be an issue for the nearby residents. The switch to electric motors will also help cut down the noise in the oil and gas operation.

The need for less maintenance of electric motors and lean burn electric generator will result in fewer maintenance trips for the oil and gas workers which will help in controlling dust as well minimize the impact on wild area in the four corners region.

Economics

The initial capitol cost of installing gas electrical generator and electrical motor would be relatively high. As an example, a generator of 1 MW capacity can approximately support 33 combustion engine of 40 HP. A general purpose 40 HP engines costs about $ 1200.00 which results in capital cost of $39,600 for replacing 33 internal combustion engine with electric motors. The approximate cost of a 1.2 MW gas-fired generator is $430,000. The total capital cost for replacing 33 engines with a gas fired generator will be about $470,000. However in long term the benefit in terms of emission reduction and saving in maintenance cost should help in recovering the initial capital cost.

The maintenance cost of one big generator is cheaper than maintenance of many smaller internal combustion engines.

The cost of running electrical wires to connect electric motors will much less than currently installed pipelines to carry natural gas for the small rich burn combustion engines.

<u>Tradeoffs</u>

In case of gas electric generators, there will be shift of emission from many internal combustion engines to one or several big internal combustion engine(s). There would be a net reduction in emissions which will depend on degree of conversion that each producer deems economically feasible.

The cost and affects of running transmission lines from generator(s) to power electrical motors for gas compression needs to be evaluated.

<u>Burdens</u>

The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary, depending upon the results of monitoring data over time.
B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies.

III. Feasibility of the option

A. Technical: The feasibility mainly depends on the close proximity of replaceable internal combustion engines and operating conditions of internal combustions engines in order of selection of gas electrical generator. The power, transmission line and substation requirements for on-site lean-burn generator system would need to be carefully considered in deciding the feasibility of this option.
B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Emissions from on-site electric generators would more than off-set the natural gas-fired engines that could be targeted for replacement (e.g., uncontrolled compressor engines or small rich burn pump jack engines).
C. Economic: Depends upon economics of ordering electrical motors, the ability of the grid system to supply the needed capacity and the cost to obtain right of way to drop a line to a potential site. Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small.

IV. Background data and assumptions used

The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff.

Gas electrical generator information was obtained from Caterpillar's Website.

V. Any uncertainty associated with the option (Low, Medium, High):

Medium based upon uncertainties of obtaining electrical easements from landowners and/or land management agencies.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups

Mitigation Option: Optimization/Centralization

I. Description of the mitigation option

Overview

- This option outlines the deployment of internal combustion engines used as the source to power various oil and gas related operations with the appropriate horsepower rated to the need of the activity being conducted. The advantages of this approach would be reducing the cumulative amount of horsepower deployed, which may reduce emissions through elimination of compression and optimization of compressor fleets. This may also be accomplished by using larger central compression in lieu of deploying numerous smaller compressor engines at a number of individual locations such as well sites.
- Overall fleets of engines in the San Juan basin are currently believed to be loaded at about 50% available hp. This is determined by looking at installed hp, volume of gas being moved, and pressure differentials in the field. These load factors are dynamic and constantly changing.
- **Differing opinion:** Emissions from compressor engines are based on the amount of fuel used (a function of capacity and load). Assuming that emission factors do not change with load (this may or may not be true), as the load is reduced emissions will decrease. If it is assumed that all engines have the same rate of emissions, simply reducing the number of engines and operating them at higher capacity will likely result in the same amount of fuel usage and the same amount of emissions. The assumption that all engines have the same emissions is not true and thus this option is based on a flawed premise. In reality, analysis of engine utilization in the region indicates that larger engines have lower emissions than smaller engines.

Air Quality and Environmental Benefits

- The benefits could be lower emissions calculated against horsepower assuming smaller horsepower engines would be deployed to replace larger engines. This would be accomplished by either design or as field conditions changed at individual sites or by centralizing compression horsepower at central site. While efficiency may improve, application of smaller engines working at or near full load may increase NOx emissions relative to an oversized unit operating at reduced load.
- **Differing opinion**: Needs to be framed for applicability to engine type, size, etc.

Economics

- Optimization:
  - The economics of replacing individual site compression with properly sized horsepower could be difficult. Some companies bought individual site compression based upon technical considerations at that time. Unfortunately, due to changing field conditions, which could not be contemplated when the original engine was bought, the existing engine may not be sized properly. To require the purchase of new compressors for changing field conditions over the life of a natural gas field will be an economic strain on the operators.
  - The salvage value of the compressor being replaced is a fraction of a new one.
  - Replacing engine compression several times during the life of well would not be economic. Purchasing new compression with operating conditions in a given field could jeopardize the economics of a well(s).
  - If the engines are rentals, the situation is much more flexible depending upon the lease/contract with the vendor. In the San Juan Basin most smaller well site

    - compression is a combination of purchased and leased, both of which depend upon the individual operator's preferences.
- Centralization
    - As with optimization, field conditions change and to size equipment properly on a horsepower basis may require numerous iterations of replacement.
    - As above with optimization, the economics of replacing units to fit ever changing field conditions in the cases where the equipment has been purchased will create economic challenges for the operators.
    - For leased units, flexibility would be greater, but would depend upon the lease/contract with the vendor.
    - Use of larger centralized engines increases the opportunity to use low emission lean burn engines.
- Lines and gathering system would probably need to be redesigned and replaced for efficiency, otherwise line losses and bottlenecking could create operation issues. Besides causing increased surface disturbance the economics of line redesign and replacement are probably beyond the economic feasibility limits of the fields in the area.

Tradeoffs

- The tradeoffs for centralization appear to have the most concern.
- There could be an air quality benefit by centralizing, but there would be more long-term surface disturbance involved and dust generation from construction. For instance, a central compressor serving multiple sites would likely need to be built at a new site making it more equitable from an operational perspective to serve its purpose. A new central site would then require surface disturbance for a new site and, whether an existing site could be used or not, underground piping from the central site to multiple sites would be necessary. This could result in permanent new disturbance (if a new site had to be built) and short-term disturbance for the pipeline to multiple sites until this was reclaimed.
- While above ground pipelines are a possibility, for safety reasons these have not been generally used in the San Juan Basin.
- Emissions tradeoffs based on relative operating loads would need to be considered.
- There is potential for increased noise for those living close to these centralized facilities.
- Potential for increased permitting.
- It is possible that centralized compressor stations would become Part 70 or 71 facilities (Title V under the CAA) and would require substantial testing and record keeping on the part of operators and agencies.

Burdens

- The burden for optimization and/or centralization would fall to industry. The cost of pursuing this approach should be carefully considered due to the impact it could have on the economic viability of a given well.
- Increased permitting places burden on regulatory agencies and industry.

II. Description of how to implement

A. Mandatory or voluntary. This option should be voluntary given the economic impacts.
B. Indicate the most appropriate agency(ies) to implement. NA; would be voluntary by the companies since they must assess the technical and economic feasibility.

III. Feasibility of the option

A. Technical: Technical concerns would include trying to size compression properly either with optimization or centralization considering the unknowns associated with changing field conditions.

B. Environmental: Potential environmental benefit would need to be more closely reviewed depending upon the specific scenario. At best, little or marginal benefits are likely to be realized.
C. Economic: While some centralized options could be considered, well-level optimization is not economically feasible considering all the variables that exist with field operations. .

IV. Background data and assumptions used

Discussions with company field and engineering staff

- Input from engine manufacturers and engine consultants

V. Any uncertainty associated with the option (Low, Medium, High)

High. For optimization: The sizing of engines is based on the maximum flow from a well. As wells decline through time the initial hp needs are no longer appropriate. Replacement of this existing hp would be cost prohibitive. For centralization: collection systems are already in place and centralizing would require retrofitting, which is cost prohibitive. Further, in NM, well sites and gathering systems have different owners. Competitors would need to collaborate to centralize, which would be unlikely.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups

None identified at this time. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Follow EPA New Source Performance Standards (NSPS)

I. Description of the mitigation option

EPA is in the process of developing the first national requirements for the control of criteria pollutants from stationary engines. Separate rulemakings are in process for compression-ignition (CI) and spark-ignition (SI) engines. These NSPS will serve as the national requirements, leaving states with the authority to regulate more stringently as might be required in unique situations.

CI NSPS: The final NSPS for stationary CI (diesel) engines was published in the Federal Register on July 11, 2006. It requires that new CI engines built from April 1, 2006, through December 31, 2006, for stationary use meet EPA's nonroad Tier 1 emission requirements. From January 1, 2007, all new CI engines built for stationary use must be certified to the prevailing nonroad standards. (Minor exceptions are beyond the scope of this discussion.)

SI NSPS: The NSPS proposal for stationary SI engines, including those operating on gaseous fuels, was published in the Federal Register on June 12, 2006. Per court order, the rule is to be finalized by December 20, 2007. Like the CI NSPS, certain elements of the SI NSPS will be retroactively effective once finalized. The following summarizes the proposed requirements:

EPA SI NSPS NPRM
NOx/CO/NMHC (g/bhp-hr)

		2007		2008		2009		2010		2011	
		1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul
All engines	≤ 25 hp			40 CFR 90							
Gasoline & RB LPG	26-499 hp			40 CFR 1048							
	> 500 hp		40 CFR 1048								
Natural gas & LB LPG											
Non-emergency	26-499 hp			2.0/4.0/1.0						1.0/2.0/0.7	
	≥ 500 hp		2.0/4.0/1.0						1.0/2.0/0.7		
Emergency	> 25 hp					2.0/4.0/1.0					
Landfill / digester gas	< 500 hp			3.0/5.0/1.0						2.0/5.0/1.0	
	≥ 500 hp		3.0/5.0/1.0						2.0/5.0/1.0		

Notes: [illegible]
Emergency engines limited to 100 hours per year for maintenance and testing.

All new stationary engines in the Four Corners region will have to meet the new EPA requirements. Deferring to the EPA NSPS will provide the most cost-effective emissions control because manufacturers will have compliant products for sale across much of the country. Compliance with the EPA NSPS will provide a level of emissions control that is federally mandated and will impose a certain financial burden that is not elective. The premise for this mitigation option is that additional control beyond the EPA NSPS would not be needed for new engines.

II. Description of how to implement

A. Mandatory: Compliance with the EPA NSPS will be mandatory. This would apply to all newly manufactured, modified and reconstructed engines after the NSPS effective dates. 'Modified' engines are those undergoing a change that would result in an increase in emissions, while 'reconstructed' engines are those undergoing rebuild work that costs at least 50% of the cost of a new unit. See 40 CFR 60.2 for further definitional details.

Differing Opinion: Voluntary: Applicability of the NSPS requirements could be considered for existing engines. Because a large number of existing engines would require extensive rework or replacement to achieve the NSPS levels, any such approach should be a voluntary, incentive-based program.

B. Indicate the most appropriate agency(ies) to implement**:** No additional work would be needed other than what EPA is mandating. Any permitting would continue to be at the State's discretion. The appropriate agencies for any incentive based applicability to existing engines would need to be determined.

III. Feasibility of the option

A. Technical: EPA has spent the past year working with engine manufacturers during its development of the CI and SI NSPS. The requirements have been shown to be technologically feasible.
B. Environmental: EPA's regulatory documents do/will provide details of the expected environmental benefits and the conclusion that this level of control is appropriate for areas not in advanced levels of non-attainment.
C. Economic: EPA's Regulatory Impact Analyses (RIA) for the two rulemakings will provide explanations of the expected costs of compliance.

IV. Background data and assumptions used

None beyond material in EPA's rulemakings.

V. Any uncertainty associated with the option (Low, Medium, High)

Essentially no uncertainty that the NSPS will soon provide new, emissions-controlled stationary engines in the Four Corners region.

VI. Level of agreement within the work group for this mitigation option

The RICE subgroup anticipates Oil & Gas Workgroup consensus that EPA's mandatory compliance with its new NSPS will provide appropriate short- and long-term emissions control that is commensurate with the needs of the Four Corners region.

VII. Cross-over issues to the other source groups

Assistance from Cumulative Effects Work Group needed to assess air quality benefits in the Four Corners area. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Adherence to Manufacturers' Operation and Maintenance Requirements

I. Description of the mitigation option

Engine manufacturers provide to end-users recommended procedures for the initial installation and adjustment of spark-ignition (SI) engines, in addition to on-going preventative maintenance recommendations. Adherence to these recommendations provides long-term, intended performance, emission levels, durability, etc. Please see EPA SI NSPS proposal update below under Section V.

II. Description of how to implement

A. Mandatory or voluntary: While adherence to engine manufacturers' 'recommended' procedures is generally voluntary from a regulatory perspective, this mitigation option instead proposes that such adherence be mandatory. This could be considered for existing engines as well as for new engines. Please see Section V below for further discussion.

B. Indicate the most appropriate agency(ies) to implement: EPA's proposed New Source Performance Standards (NSPS) for, in particular, SI engines, includes several related aspects that will likely be mandatory. Those aspects of engine manufacturers' recommended procedures that are not included in the NSPS could be implemented by the states.

1. 40 CFR 60.4234: **"Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in 60.4233 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine."**

2. 40 CFR 60.4241(f): "Manufacturers may certify their engines for operation using gaseous fuels in addition to pipeline-quality natural gas; however, the manufacturer must specify the properties of that fuel and provide testing information showing that the engine will meet the emission standards specified in 60.4231(d) when operating on that fuel. **The manufacturer must also provide instructions for configuring the stationary engine to meet the emission standards on fuels that do not meet the pipeline-quality natural gas definition.** The manufacturer must also provide information to the owner and operator of the certified stationary SI engine regarding the configuration that is most conducive to reduced emissions where the engine will be operated on particular fuels to which the engine is not certified."

3. 60.4243: "**If you are an owner or operator, you must operate and maintain the stationary SI internal combustion engine and control device according to the manufacturer's written instructions** or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators of certified engines may only change those settings that are allowed by the manufacturer to ensure compliance with the applicable emission standards. ...The engine must be installed and configured according to the manufacturer's specifications to ensure compliance with the applicable standards."

4. 60.4245(a): **"Owners and operators of all stationary SI ICE must keep records of...maintenance conducted on the engine."**

III. Feasibility of the option

A. Technical: Prudent operators follow manufacturers' recommended procedures. Properly maintained engines operate more efficiently and at lower total cost. Ignition maintenance, in particular, can have significant impact on the performance and life of catalysts.

B. Environmental: Properly maintained engines produce lower emissions. Instead of a fix-as-fail mentality, proper maintenance can avoid or detect failed O_2 sensors or spark plugs, thus avoiding an increase in HC and CO.
C. Economic: The overall, long-term cost of a properly maintained engine is lower than that of a neglected engine.

IV. Background data and assumptions used

V. Any uncertainty associated with the option Medium. EPA NSPS Update: Mandatory requirement to follow engine manufacturers' recommendations is included in the proposal for optionally certified engines. For engines not certified by engine manufacturers, the owner/operator would have compliance responsibility and would not be required to follow the engine manufacturers' recommendations. Owner/operators are raising concern with EPA over the proposed requirement to follow engine manufacturer recommendations for certified engines or follow the proposed option to seek engine manufacturer approval for alternative operational procedures. Many owner/operators believe their own time-proven procedures are appropriate. Because EPA's final rule will have carefully considered the implications of operational and maintenance practices, the Agency's final outcome should be appropriate for new engines used in the Four Corners area. Any consideration of those requirements for existing engines would need to assess the potential benefits achievable through altering current field practices.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups

Mitigation Option: Use of SCR for NOx control on lean burn engines

I. Description of the mitigation option

NOx emissions from lean burn engines (natural gas and diesel fueled) can be reduced by chemically converting NOx into inert compounds. The most effective equipment to achieve NOx reductions is an SCR (selective catalytic reduction) system.
Differing opinion: SCR is one effective equipment option to achieve NOx reductions.
Reactant injection of industrial grade urea, anhydrous ammonia, or aqueous ammonia is required to facilitate the chemical conversion. The overall catalyst reaction is as follows:

$$NH_3 + NO + NO_2 > N_2 + H_2O$$

The SCR systems utilize programmable logic controller (PLC) based control software for engine mapping/reactant injection requirements. Sampling cells are utilized for closed loop feedback of dosing requirements depending on the amount of NO measured downstream of the catalyst bed.

SCR system components include catalyst housing, housing insulation, control/dosing panel, exhaust dosing/mixing section, and reactant injector. Depending on the reactant medium, a storage tank will be required with a potential minimum temperature requirement of 40°F. **Differing opinion:** Heated reactant storage may drive limited applicability. Description should be expanded to address handling, associated regulations with monitoring and testing for the system slip and RMPs if applicable. Electrical supply to run the SCR system and instrumentation is required.

SCR systems can be constructed with the addition of oxidation catalysts, for the added conversion requirements of CO, VOCs and Formaldehyde. This oxidation catalyst is a dry reaction and is not dependant on injection of a reactant. See the mitigation option on the use of oxidation catalysts for reduction levels achieved for the pollutants.
Differing opinion: Mitigation Option is 'Use of SCR for NOx control on lean burn engines'; therefore, this paragraph may be out of context.

II. Description of how to implement

A. Mandatory or voluntary
Voluntary: May be enhanced by the state supplementing a percentage of the cost.
B. Indicate the most appropriate agency(ies) to implement

III. Feasibility of the option

A. Technical: Dependent on site readiness, installation and start-up would require 7-10 days. **Differing opinion:** Heated reactant storage may drive limited applicability, especially if power is unavailable. Concerns include security risk, handling, safety standards, applicability of RMPs and other associated regulations for monitoring and testing of the system slip. There have been no known applications of this technology for remote unattended oil and gas operations. At the present time there is insufficient information to quantify achievable emission reductions in unattended facilities. The incremental cost to control on lean burn technology is likely to be very high because of the small incremental additional mass reductions as a result of tertiary add on controls. Because SCR uses a dilute aqueous solution, RMP hazards are typically not a concern.
Excessive ammonia slip within a coherent NOx plume may lead to increased NO_3 formation. This could result in degradation of visibility even though NOx emissions are reduced.

B. Environmental: Post catalyst NOx levels of <0.15g/bhp-hr.
Differing opinion: <0.15 g/bhp-hr depends on the start point but could imply 95% or greater control. Catalysts optimally start at 90-95% capability but drop over time. Control is sensitive and if it moves off

set point, result is ‘no’ control (vs. reduced control). What is the origin of the stated NOx levels? On what type of engine in what type of service? This appears to be simply an assertion with no backup or verification.

<u>C. Economic</u>: Cost of SCR system and maintenance are an increased cost to the packager and end user. The five-year cost for SCR on a 3-engine rig in the Jonah/Pinedale area of Wyoming was estimated at $5 MM in a demonstration pilot conducted by Shell. This information is available from the Wyoming DEQ.
Differing opinion: Costs of heated storage, additional regulatory compliance, added manpower and increased site security would be the burden of the operator. In addition, the engine must be highly stable for this control to be effective (see environmental note).
See also Cumulative Effects Analysis for this option for further emissions analysis.

IV. Background data and assumptions used

V. Any uncertainty associated with the option (Low, Medium, High)

Medium. Negative perception of reactant handling and injection, though the technology has proven itself to be very user friendly.
Differing opinion: HIGH: The assertion that this is “user friendly” technology is not aligned with the experiences documented as part of the pilots noted above. In these pilots, the systems required both a vendor representative and consultant on site to keep them operating correctly. Concerns include heating reactant, security risk, handling, safety standards, applicability of RMPs and other associated regulations for monitoring and testing of the system slip.
Modeling needs to be conducted to evaluate the potential improvement in ambient air quality (ozone, deposition and visibility).

VI. Level of agreement within the work group for this mitigation option

<u>VII. Cross-over issues to the other source groups</u> (please describe the issue and which groups) None.

Differing opinion: The CE group needs to offer an opinion on the effect of additional ammonia emissions at plume height.

See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Use of NSCR / 3-Way Catalysts and Air/Fuel Ratio Controllers on Rich Burn Stoichiometric Engines

I. Description of the mitigation option, including benefits (air quality, environmental, economic, other) and burdens (on whom, what)

NO_X, CO, HC, and Formaldehyde emissions from a stoichiometric engine can be reduced by chemically converting these pollutants into harmless, naturally occurring compounds of nitrogen, carbon dioxide and water vapor. The most common method for achieving this is through the use of a catalytic converter. In a catalytic converter, the catalyst will either oxidize (oxidation catalyst) a CO or fuel molecule or reduce (reduction catalyst) a NO_X molecule. The general catalyst reactions are as follows:

$$NO + CO = N_2 + CO_2$$
$$NO_X + CH_4 = N_2 + CO_2 + H_2O$$
$$NO_X + H_2 = N_2 + H_2O$$

These reactions are reducing the NO_X to nitrogen and oxidizing the fuel and CO molecules. These reactions oxidize some of the CO and NMHC molecules, however further conversion is accomplished with and oxidizing catalyst. The oxidizing reactions are shown below:

$$CO + O_2 = CO_2$$
$$CH_4 + O_2 = CO_2 + H_20$$
$$CnHm + O_2 = CO_2 + H_20$$
$$H_2 + O_2 = H_2O$$

A 3-way catalyst contains both reduction and oxidation catalyst materials and will convert NO_X, CO, and NMHCs to N_2, CO_2, and H_2O. A process which causes reaction of several pollutant components is referred to as a Non Selective Catalyst Reduction (NSCR). NSCR is applicable only on stoichiometric engines. A very narrow air/fuel ratio operating range is necessary to maintain the catalyst efficiency. This can only be consistently maintained by utilizing electronic air/fuel ratio controls.

Maintaining low emissions in a stoichiometric combustion engine using exhaust gas treatment requires a very closely regulated air/fuel ratio. Without an air/fuel ratio controller, emission reduction efficiencies vary through the catalyst. Many Air/Fuel Ratio Controllers (AFRCs) are available on the market today. AFRCs are available from both the engine manufacture or can be purchased from an after-market supplier. Most controllers utilize closed loop control based on the readings of an exhaust gas oxygen sensor to determine the air/fuel ratio.

Air/Fuel Ratio Control will only maintain an operator-determined set point. For this set point to be at the lowest possible emissions setting an exhaust gas analyzer must be utilized. Operators should utilize quarterly emission tests to ensure units are maintaining compliance.

Differing opinion: This mitigation option is distinct from the mitigation option on using oxidation catalysts on lean burn engines because NSCR controllers are applied only to rich burn engines. Only applies to true rich burn engines, not effective for 1-2% rated rich-burns. 3-way catalysts are only applicable to stoichiometric (true rich burn) engines, potential is to drive the exhaust temperature up. Oxygen, oil slip past engine rings, and poor fuel quality may destroy the catalysts.

II. Description of how to implement

A. Mandatory or voluntary:

Voluntary: May be enhanced by state funding a percentage of the cost.

Mandatory: Mandatory enforcement would give the state the power to eliminate, at the minimum, 90% of NO_X, CO, HC, and Formaldehyde emissions from stationary elements.
Differing Opinion: This option should be mandatory, implemented and enforced by the states.
Differing Opinion: 90% is a reasonable not minimum control for NOx and CO, but HC and Formaldehyde are not straightforward to measure or to define. Catalysts are in a constant state of decline during operation and require periodic cleaning or replacement. 90% control is contingent on closely monitored and regulated air/fuel ratio. A more likely/achievable reduction of NOx is in the 80% range and can only be achieved with well operated and maintained engines/AFR's where the load is stable in nature. Variable loads result in less than optimum air/fuel ratios and less reduction.

B. Indicate the most appropriate agency(ies) to implement: States, Tribes and/or BLM, due to the fact that they are already involved in air quality regulations.
Differing opinion: Mandatory implementation of this requirement would only be feasible in a well-crafted permit program administered by the agency having jurisdiction for air quality. BLM does not have regulatory authority for air quality. Although Tribes may have air quality administration authority, very few functional Tribal programs currently exist.

III. Feasibility of the option

A. Technical**:** Engines can be retrofitted in the field ½ a day or less. Catalysts do have a life span and will lose their efficiencies. However, under ideal operating parameters and with consistent engine maintenance, the life span of a catalyst can easily be up to 5 years. Catalysts can be washed to increase the lifespan in the case of oil spray or ashing. AFRC oxygen sensors should be replaced quarterly to assure constant compliance. Fuel quality limitations are notable, i.e. field gas, biofuel, etc. may damage catalysts.
Differing Opinion: The previous statement is inaccurate; if an engine can be retrofitted, the exhaust system has to be dismantled and rebuilt. Not all engines will accept an after-market add on of AFRC. Usually, the added controls require a new base, piping and if applicable, tear down and modification of protective building/fencing. If the engine is portable/skid mounted, this may prohibit it remaining portable. Retrofit installation of catalyst housings and units typically require additional support structure.

B. Environmental**:** Minimum of 90% NO_X, CO, HC, and Formaldehyde emission reduction. Some increase in ammonia emissions would result, however, it is not known if this increase would be significant.
Differing opinion: 90% is a reasonable not minimum control for NOx and CO, but HC and Formaldehyde are not straightforward to measure or to define. Catalysts are in a constant state of decline during operation and require periodic cleaning or replacement. 90% control is contingent on closely monitored and regulated air/fuel ratio. A more likely/achievable reduction of NOx is in the 80% range and can only be achieved with well operated and maintained engines/AFR's where the load is stable in nature. Variable loads result in less than optimum air/fuel ratios and less reduction. Issues Associated With the Use of NSCR on Existing Small Engines:

- Engines Operate at Reduced Loads and There is a Problem Maintaining Sufficient Stack Temperature for Catalyst to Work
- On Engines with Carburetors, Difficulty Having the AFR Maintain a Proper Setting
- On Older Engines the Linkage and Fuel Control May not Provide "Fine Enough" Control
- If the AFR Drifts Low, NH_3 Will be Formed in Roughly Equal Amounts to NOx Reduced

C. Economic**:** The cost of catalyst and AFRC are an added cost to both packager and end user, however, as technologies have advanced, producers have a number of cost effective options. The fact of the matter is the cost to the producer to maintain compliance is much greater than the cost of a catalyst or AFRC. In order to maintain compliance of any kind, the producer is forced to have more manpower, more thorough engine maintenance programs, and adequate testing of their units to assure that they are in constant compliance. Caterpillar recommends monthly testing with portable analyzer. See approximate control cost analysis as of January 2007 for an example of the cost of NSCR control.

	NSCR Retrofit Costs		
	Compressco Ford 460	*Wauk. 220/330*	*Comments*
Catalyst Housing Purchase	*$2,120*	*$1,600*	
Catalyst Housing Purchase w/Silencer	*$2,650*	*$1,950*	
Average Housing Purchase	*$2,385*	*$1,775*	
Catalyst Element Purchase	*$1,000*	*$800*	
Air Fuel Ratio Controller Purchase	*$2,950*	*$2,950*	
"Rebuild" of Fuel and Air Control System on Older Engines			
Electricity for Air Fuel Ratio Controller - Purchase of solar power unit	*$350*	*$350*	*Alternator and Battery or Solar and Battery*
Installation of Housing and Catalyst	*$1,080*	*$1,080*	*Assumes one welder and one helper for one full day*
Installation/Modification of Support for Housing and Exhaust	*$300*	*$300*	*Estimate of materials - Labor in item above*
Installation of Electricity	*$540*	*$540*	*Electrician or Mechanic for 1/2 day - includes travel to and from*
Installation and Set-up of Air Fuel Ratio Controller	*$2,160*	*$2,160*	*Electrician or Mechanic and Instrument Technician for one day - includes travel time to and from*
Incremental Skid Cost for New Engine	*$1,000*	*$1,000*	
Taxes, Freight, Etc. (From EPA Manual)	*$1,077*	*$1,077*	
Total Purchase and Installation - Retrofit	*$11,842*	*$11,032*	
Total Purchase and Installation - New	*$8,225*	*$7,415*	
Maintenance Cost			
Quarterly Change of O2 Sensor + Emissions Monitoring - annual cost	*$320*	*$320*	
Labor/Travel for Above	*$540*	*$540*	*Technician for 1/2 day - includes travel to and from*
Annualized Catalyst Replacement (5 yr life)	*$160*	*$160*	
Total Annual Cost	*$1,020*	*$1,020*	

IV. Background data and assumptions used

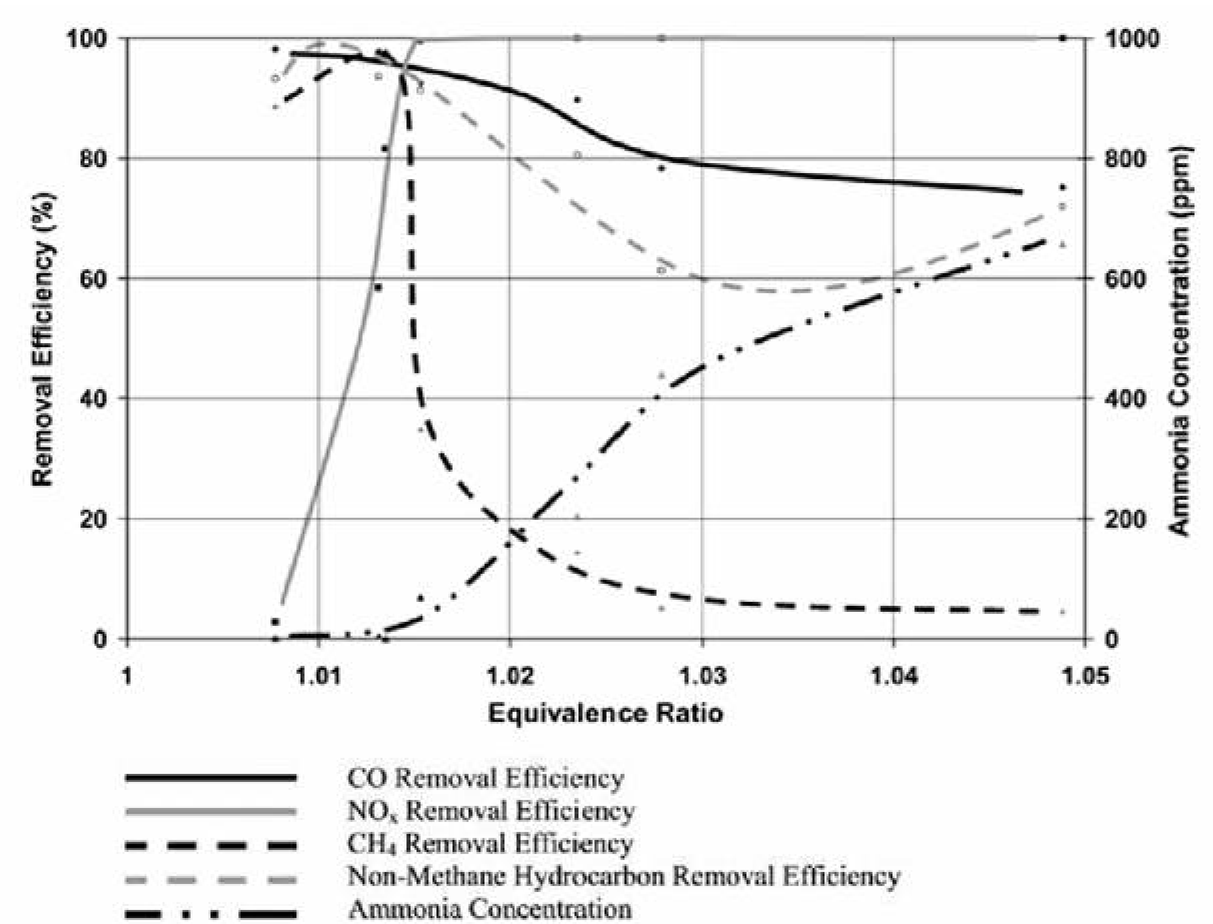
1. G. Sorge "Update on Emissions"

Differing opinion: Insufficient information to locate reference.

V. Any uncertainty associated with the option (Low, Medium, High)

LOW, this is a proven technology with years of results. One issue of merit is the production of ammonia through a 3-way catalyst. This issue has been thoroughly researched and the following are the generalized results:
Differing Opinion: MEDIUM: HC is difficult to measure. Drift of control and narrow applicability to only 'true' rich burn engines are significant issues.

The problem of NH3 formation across catalyst equipped rich burn CNG engines is associated with problems of the A/F controllers. If the A/F ratio is allowed to drift rich, considerable NH3 can be formed. This is shown in the following graph:



Differing opinion: Reference is needed for the Graph credentials.

For a variety of reasons the A/F controllers have failed to control at the desired set point, 0_2 sensors failing, a not particularly sophisticated controller, etc. Today's AFRCs are very exact machines with the ability to easily maintain a precise set point. If a rich burn engine is operated with a properly functioning air/fuel ratio controller plus 3-way catalyst, it will meet emissions requirements without producing a noticeable amount of ammonia.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups None at this time.
Differing Opinion: The CE group needs to offer an opinion regarding the impact of increased ammonia emissions in the region. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Use of Oxidation Catalysts and Air/Fuel Ratio Controllers on Lean Burn Engines

I. Description of the mitigation option

CO, HC, and Formaldehyde emissions from a lean burn engine can be reduced by chemically converting these pollutants into harmless, naturally occurring compounds, such as carbon dioxide and water vapor. Lean Burn Engines already have low uncontrolled NO_X emission values (Lean burn engines are a form of NOx control and therefore do not have uncontrolled emissions). The most common method for achieving this is through the use of a catalytic converter. In a catalytic converter, the oxidation catalyst will oxidize (oxidation catalyst) a CO or fuel molecule. The most common method for achieving CO, HC and formaldehyde control this is through the use of an oxidation catalytic converter. The general oxidizing reactions are shown below:

$$CO + O_2 = CO_2$$
$$CH_4 + O_2 = CO_2 + H_20$$
$$CnHm + O_2 = CO_2 + H_20$$
$$H_2 + O_2 = H_2O$$

Air/fuel ratio control helps to maintain the catalyst efficiency. This can only be consistently maintained by utilizing electronic air/fuel ratio controls. However, most air/fuel ratio controllers are utilized to maintain engine performance due to ambient conditions. While it is true that lean burn engines perform better with AFRC units they are not needed for oxidation catalyst performance – the exhaust stream in a lean burn engine has sufficient oxygen under all conditions where the engine will run.
Differing opinion: An electronic air/fuel ratio controller is recommended to help maintain the catalyst efficiency.

Maintaining low emissions in a lean combustion engine using exhaust gas treatment is enhanced by the use of an Air/Fuel Ratio Controller, however, not necessary. Many Air/Fuel Ratio Controllers (AFRCs) are available on the market today, from both the engine manufacture in certain cases and after-market suppliers. Most controllers utilize closed loop control based on the readings of an exhaust gas oxygen sensor to determine the air/fuel ratio.

Air/Fuel Ratio Control will only maintain an operator-determined set point. For this set point to be at the lowest possible emissions setting an exhaust gas analyzer must be utilized. Operators should utilize quarterly emission tests to ensure units are maintaining compliance.

Differing opinion: The preceding two paragraphs seem out of place in the context of oxidation catalyst.

II. Description of how to implement

A. Mandatory or voluntary**:**
Voluntary: May be enhanced by state funding a percentage of the cost.
Mandatory: Mandatory enforcement would require give the state the power to eliminate, at the minimum, 90% of CO, HC, and Formaldehyde emissions from stationary elements. Lean Burn Engines already have low uncontrolled NO_X emission values.
Differing Opinion: This option should be mandatory, implemented and enforced by the states.
Differing Opinion: 80% CO destruction is a more likely/sustainable reduction for CO and HC's. Formaldehyde destruction/control is less certain but is lower than CO or HC's.
Differing Opinion: 90% is a reasonable not minimum control for CO; but HC and Formaldehyde are not straightforward to measure or to define. Catalysts are in a constant state of decline during operation and require periodic cleaning or replacement. 90% control is contingent on closely monitored and regulated air/fuel ratio.

B. Indicate the most appropriate agency(ies) to implement**:** States, Tribes and/or BLM, due to the fact that they are already involved in air quality regulations.
Differing Opinion: BLM is not appropriate since they are not charged with air quality management. This is the role and responsibility of the States or Tribes.

III. Feasibility of the option
A. Technical**:** Engines can be retrofitted in the field ½ a day or less. Catalysts do have a life span and will lose their efficiencies. However, under ideal operating parameters and with consistent engine maintenance, the life span of a catalyst can easily be up to 5 years. Catalysts can be washed to increase the lifespan in the case of oil spray or ashing. AFRC oxygen sensors should be replaced quarterly to assure constant compliance.
Differing Opinion: The previous sentence should be deleted – it is not applicable to oxidation catalyst.
Differing Opinion: The previous statement is inaccurate; if an engine can be retrofitted, the exhaust system has to be dismantled and rebuilt. Not all engines will accept an after-market add-on of AFRC. Usually, the added controls require a new base, piping and if applicable, tear down and modification of protective building/fencing. If the engine is portable/skid mounted, this may prohibit it remaining portable. Typically, retrofit will require additional support structure for the
B. Environmental**:** Minimum of 90% CO, HC, and Formaldehyde emission reduction.
Differing Opinion: 90% is a reasonable not minimum control for CO; but HC and Formaldehyde are not straightforward to measure or to define. Catalysts are in a constant state of decline during operation and require periodic cleaning or replacement. 90% control is contingent on closely monitored and regulated air/fuel ratio.

According to the EPA speciate database, the majority of HC emissions from RICE are methane (C1), which is not a regulated pollutant under the Clean Air Act. Methane is unregulated because it does not enter into photochemical reactions that form ozone. Therefore, from a THC or more importantly a VOC perspective, such controls will do little to improve ambient air quality. Realistic modeling analyses that focus on population exposure should be performed to evaluate exposure to formaldehyde. 80% CO and HC reduction is more likely in an operational mode. HCHO destruction is not completely understood but is lower than CO or HC.
C. Economic**:** The cost of catalyst and AFRC are an added cost to both packager and end user, however, as technologies have advanced, producers have a number of cost effective options. The fact of the matter is the cost to the producer to maintain compliance is much greater than the cost of a catalyst or AFRC. In order to maintain compliance of any kind, the producer is forced to have more manpower, more thorough engine maintenance programs, and adequate testing of their units to assure that they are in constant compliance.

IV. Background data and assumptions used 1. G. Sorge "Update on Emissions"
Differing opinion: Insufficient information to locate reference

V. Any uncertainty associated with the option (Low, Medium, High) LOW, this is a proven technology with years of results.
Differing Opinion: The uncertainty is not in the emission reduction technology. The uncertainty is in the ambient air quality benefits that would be achieved as a result of implementation of this option.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups None at this time. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Install Lean Burn Engines

I. Description of the mitigation option

Using gas fueled (reciprocating) **Lean Burn Engines** as the main prime mover in gas compression and generator set applications in the Four Corners area.

Gas engines are the predominant prime mover used to power gas compressor packages. Gas engines are classified as either Rich Burn or Lean Burn. The industry acknowledges a lean burn engine to have an oxygen level measured at the exhaust outlet of about 7-8%. This typically translates into a NOx emissions rating of 2 g/bhp-hr or less. This will be federally mandated through NSPS regulations requiring performance at this rating for both Lean Burn and Rich Burn engines. Currently, a large percentage of engines operating in the Four Corners Area that have a capacity of greater than 500 hp use lean burn technology and achieve, on average, a NOx emission rating of less than 2 g/hp-hr.

Lean burn engines have this lower NOx rating without using a catalyst or any other form of emissions after-treatment. Some lean burn engine incorporate an Air Fuel Ratio Control installed at the engine manufacturing plant.

Typically lean burn engines have a HP rating above 300 HP. This reflects today's manufacturing emphasis.

The main advantage of using a lean burn is in its capability to offer low emissions without after-treatment. In addition, lean burn engines operate at cooler temperatures and may offer longer life between major repairs.

II. Description of how to implement

A. Voluntary – lower emissions should be the goal. How the operator gets there is his selection and responsibility. In other words, allow an operator to either use a lean burn engine without emissions after-treatment or a rich burn engine with emissions after-treatment to achieve the emissions level needed. It is important to note that the majority of engines greater than 500 hp located on the Southern Ute Reservation where there is no minor source permitting program are lean burn or are low emitting engines as a result of post catalyst treatment. This has been a voluntary effort from the operators.

B. Most appropriate agency to implement: EPA and state air boards.

III. Feasibility of the option

A. Technical: Some states have shown preference to accept engines with lean burn technology over rich burn engines using after-treatment. But as of mid-2006 no engine manufacturers offer the lean burn engine at less than 300 HP. So manufacturers would have to develop a new engine to meet this requirement.

B. Environmental: Study the effect of HAPs formation in lean burn emission and whether further reduction is necessary. There has been extensive testing on HAP emissions from lean burn engines and EPA has established MACT standards for major HAP sources that pertain to RICE. Realistic modeling analyses that focus on population exposure should be performed to evaluate exposure to formaldehyde. The consolidated engine rule for SI engines will require HCHO control.

C. Economic: This is the best economic solution when the power rating is available and the total emissions for all pollutants meet the requirement. Typically this is a more economically viable solution than having a rich burn engine with added controls, catalysts and air to fuel ratio.

IV. Background data and assumptions used

Since there are no known lean burn engines under 300 hp, engine manufacturers may be interested in developing them. The development of these engines may be the most acceptable solution to users, EPA, and states. The forthcoming NSPS will encourage engine manufacturers to develop lean burn engines under 300 hp.

V. Any uncertainty associated with the option (Low, Medium, High)

The uncertainty is not in the lean burn technology but in the ability to meet the air emission requirement across all hp ratings (from 25 - 425 hp) and the acceptance of the final composition of the exhaust gases (including HAPs).

Manufacturers are not unwilling to create new technologies but there is a risk associated with the types of investment returns on technologies developed for small engines.

VI. Level of agreement within the work group for this mitigation option

Some believe that after-treatment is the best option. This is acceptable to an engine manufacturer but this option adds cost related to the additional equipment needed, permitting and monitoring process. In addition, there is the suspicion that engines with after-treatment may be working out of compliance at any one point.

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

A study should be conducted on what would achieve the lowest emissions:

- lean burns with no after-treatment
- lean burns with oxidation catalysts and AFRs
- or rich burns with catalysts and AFRs.

From the results, select the option that produces the lowest emissions.

Mitigation Option: Interim Emissions Recommendations for Stationary RICE

I. Description of the mitigation option

The following mitigation option paper is one of three that were written based on interim recommendations that were developed prior to the convening of the Four Corners Air Quality Task Force. Since the Task Force's work would take 18-24 months to finalize, and during this time oil and gas development could occur at a rapid pace, an Interim Emissions Workgroup made up of state and federal air quality representatives was formed to develop recommendations for emissions control options associated with oil and gas production and transportation. The Task Force includes these recommendations as part of its comprehensive list of mitigation options.

Require a 2 g/bhp-hr limit on engines less than 300 HP:

- May lead to 60 to 80 percent reduction in NOx.
- Help with visibility impairment in Class I areas in four corners region. Monitoring data at Mesa Verde and Weminuche Class I Areas clearly shows that NOx (NO3) is responsible for a very small fraction of visibility impairment. Modeling studies using the EPA CALPUFF model suggest that NO3 is responsible for visibility impairment in the Class I Areas. There are numerous examples that demonstrate that CALPUFF significantly over estimates NO3 visibility impairment compared to monitoring data.
- Several manufacturers offer engines that meet this specification, commercially available in two stroke engines only. Four stroke Lean burn engines capable of meeting 2 g/bhp-hr are not yet commercially available in sizes < 300hp.
- NSCR catalytic reduction can be added at reasonable cost. Potential engine durability concerns associated with elevated exhaust temperatures must be addressed when considering reasonable costs of installation of NSCR.
- Ammonia emissions may increase from use of NSCR catalyst.
- Increased ammonia may or may not affect visibility in the region.
- Without implementation, air quality standards may be exceeded.

Require a 1 g/bhp-hr limit on engines larger than 300 HP:

- Lean burn technology is widely available from manufacturers.
- The lean burn technology will help protect visibility in the region.
- The NAAQS and PSD increments will be less affected.
- Deposition of NOx and related compounds would be reduced
  Differing Opinion: Analysis of engine quarterly flue gas testing results indicates that, on average, it is possible to achieve an emission limit of 1 g/hp-hr, however, it may not be possible to achieve this emission level on a continuous basis.

II. Description of how to implement

These limits should be mandatory for all new and relocated engines and potentially for existing engines as well. The most appropriate agencies to implement this would be the FLMs and the New Mexico, Colorado and Southern Ute environment departments.

Existing fleet has limited compressors that meet these performance criteria. Based on NMAQ Letter of Instruction dated August 2005, <300 hp compressors must meet 2g/hp-hr. It should be noted that BLM does not have air quality authority to require any particular emissions performance from engines. This should be implemented through a well crafted minor source permit program administered by the air quality agencies.

Implementation Status for this Mitigation Option
BLM in New Mexico is currently requiring compressor engines 300 horsepower or less to have NOx emissions limited to 2 grams per horsepower hour as a Condition of Approval for their Applications for Permit to Drill. Effective August 1, 2005, BLM New Mexico, Farmington Field Office (FFO) started adding to each APD issued on and after this date a Condition of Approval (COA) requiring a limit on NOx emissions if operator placed a compressor on the location. The specific condition language states the following:

> This permit is contingent on compliance with the New Mexico Environmental Department, Air Quality Bureau's directive that compressor engines 300 horsepower or less have NOx emissions limited to 2 grams per horsepower hour.

This was based on correspondence received by the NM Air Quality Bureau dated June 3, 2005 and June 5, 2005. The FFO developed the language for the COA, which was reviewed by the NM Air Quality Bureau. The operators are required to comply with this COA regardless of whether it is a newly built compressor or a compressor that they bring in from another location or their ware yard and regardless of when the operators places the compressor on the location (i.e. six months later or two years later etc.).

BLM and USFS permits in the Northern San Juan Basin in Colorado involving new and replacement stationary internal combustion gas field engines require the following emission limits, on an interim basis:

- <u>Emission Control (small gas field engines)</u>: All new and replacement internal combustion gas field engines of less than or equal to 300 design-rated horsepower must not emit more than 2 grams of nitrogen oxides (NOx) per horsepower-hour. This requirement does not apply to gas field engines of less than or equal to 40 design-rated horsepower.

- <u>Emission Control (large gas field engines)</u>: All new and replacement internal combustion gas field engines greater than 300 design-rated horsepower must not emit more than 1.5 gram of NOx per horsepower-hour.

Interim NOx emission requirements for permits on other BLM and USFS lands in southwestern Colorado have not been established at this time. It is expected that NOx emission requirements will be implemented for these areas in the near future, either as a result of several ongoing planning efforts, or on an interim basis until these planning documents are completed.

Interim NOx emission requirements have not been established for gas field engines on the Southern Ute Indian Reservation at this time. Discussions between the Southern Ute Indian Tribe, State of Colorado Environmental Commission, US EPA Region 8, BLM and BIA are ongoing, and it is expected that NOx emission requirements will be implemented for this area in the near future.

<u>III. Feasibility of the Option</u>
The feasibility of a 2 g/bhp-hr limit has been demonstrated and equipment is commercially available. The economic feasibility is acceptable for new engines since the equipment is somewhat more expensive. Economic feasibility is acceptable for many new engines since the equipment is somewhat more expensive.
Differing Opinion: A number of new and existing engines cannot accept NSCR due to potential durability concerns associated with elevated exhaust temperatures during the needed stoichiometric operation, especially at low or varying loads.
The technical feasibility of a 1 g/bhp-hr limit has been demonstrated in commercial applications. The environmental benefits are significant. New lean burn engines can achieve this emission limit with no add-on controls, and rich burn engines can utilize add-on controls to achieve this limit. The cost is

acceptable given the large amounts of gas being compressed by these engines. **Differing Opinion:** The previous statement is subjective and unsubstantiated without supporting data. Need cost benefit analysis to determine acceptable levels. Only the new generation of lean burn engines are capable of meeting a 1 gram performance and then only with AFRC units and near full load.

IV. Background data and assumptions used

The 2 g/bhp-hr limit is based on existing engine technology in conjunction with an NSCR catalyst. The assumptions are that these engines are more than 40 HP and less than 300 HP and that they are natural gas fueled. Further, these engines would be operated with an air fuel ratio controller. The technology for the 1 g/bhp-hr engines larger than 300 HP in natural gas is well established. Although the technology is well established, it will not be commercially available for all engines until 2010. There are large engines available that have a vendor guarantee of emissions approaching 1 g/hp-hr, however, the issue is maintaining emissions at this level on a continuous basis. The new generation lean burn engines in larger sizes will meet 1 g/bhp-hr performance if equipped with AFRC units and operated near full load.

V. Any uncertainty associated with the option

The uncertainty associated with this option is the potential formation of ammonia emissions as a result of add-on controls. Ammonia emissions could worsen the air quality in the region. (See ammonia monitoring mitigation option paper.]

VI. Level of agreement within the work group for this mitigation option TBD.

Differing Opinion: EPA has proposed a 1.0 g/bhp-hr NOx limit for new SI engines, $\geq$ 500 hp, built on or after July 1, 2010, and for new SI engines, 26-499 hp, built on or after January 1, 2011. While these potential requirements are not expected to be finalized until December 20, 2007, engine manufacturers have already had to initiate engineering work in anticipation of this 1.0 gram requirement. Although a number of lean-burn engines can meet this requirement now, EPA chose the effective dates based upon the fact that other lean-burn engines need the additional time to meet the standards. Cummins has initiated significant work requiring significant resources to modify those engines to achieve the forthcoming 2.0 g/bhp-hr NOx standard. Cummins believes that the incremental benefit offered by a potential pull-ahead of the 1.0 gram standard for larger engines versus the EPA requirement for 2.0 grams NOx soon to be effective followed by the 1.0 gram standard three years later would likely be difficult to justify. Such a pull-ahead, without sound justification, would undermine the substantial work being done by EPA and engine manufacturers in moving toward a national requirement that is to avoid similar, yet different, requirements.

VII. Cross-over issues to the other source groups

The cumulative effects and monitoring groups need to address the concerns with ammonia emissions.

Mitigation Option: Next Generation Stationary RICE Control Technologies – Cooperative Technology Partnerships

This option paper investigates the status of five (1-5) new and/or evolving emissions-control technologies. They are: laser ignition, air-separation membranes, rich-burn engine with three-way catalyst, lean-burn NOx catalyst, and Homogeneous-Charge Compression-Ignition (HCCI) Engine.

Laser ignition is under development in the laboratory, but it has not reached a point where technology transfer viability can be determined.

Air separation membranes have been demonstrated in the laboratory, but have not been commercially available because the membrane manufacturers do not have the production capacity for the heavy-duty trucking industry. Since stationary engines are a smaller market, there is a high probability that the membrane manufacturers could ramp up production in this area.

Rich-burn engines with three-way catalysts borrow from the well-developed automobile industry. It is applicable to smaller engines for which lean-burn technology is not available.

There are several variations of lean-burn NOx catalysts, but the one of most interest is the NOx trap. NOx traps are being used primarily in European on-road diesel engines, but are expected to become common in the U.S. as low-sulfur fuel becomes available. Applicability to lean-burn natural-gas engines is possible but it will require a fuel reformer to make use of the natural gas as a reductant.

1. Laser Ignition

<u>I. Description of the mitigation option</u>

Overview

Laser ignition replaces the conventional spark plugs with a laser beam that is focused to a point in the combustion chamber. There, the focused, coherent light ionizes the fuel-air mixture to initiate combustion. Applicability is primarily to lean burn engines, although laser ignition could be applied to rich burn engines. Compared to rich-burn engines, lean burn engines, which are significantly more efficient, require much higher ignition voltage with spark plugs, whereas it takes lower ignition energy with laser system.

Advantages of laser ignition compared to spark plugs include: 1. Longer intervals between shutdowns for maintenance because wear of the electrodes is eliminated, 2. More consistent ignition with less misfiring because higher energy is imparted to the ignition kernel, 3. The ability to operate at leaner air-fuel mixtures because higher energy is imparted to the ignition kernel, 4. The ability to operate at higher turbocharger pressure ratio or compression ratio because the laser is not subject to the insulating effect of high-pressure air - air at higher pressure requires a higher voltage to make the spark jump the gap, and, 5. Greater freedom of combustion chamber design because the laser can be focused at the geometric center of the combustion chamber, whereas the spark plug generally ignites the mixture near the boundary of the combustion chamber.

However, laser ignition has some unresolved research issues that must be resolved before it can become commercially available. These include: 1. Lasers are intolerant of vibration that is found in the engine's environment. 2. Some means of transmitting the laser light to each combustion chamber should be developed while accommodating relative motion between the engine and the laser. This might be done with mirrors or with fiber optics. Fiber optics generally lead to a simpler solution to the problem. 3. Current fiber optics is limited in the energy flux they can transmit. This leads to a less-than-optimum energy density at the focal point. 4. Wear of the fiber optic due to vibration may limit its lifetime. 5. The cost of a laser is such that multiple lasers per engine are too expensive. Therefore, a means of distributing the light beam with the correct timing to each cylinder must be developed.

Air Quality and Environmental Benefits

Although laser ignition could be applied to rich burn engines, environmental benefits would accrue to lean burn engines. Air quality and environmental benefits are difficult to quantify at the current state of development. The more consistent ignition compared to spark ignition can be expected to decrease emissions of unburned hydrocarbons. The ability to operate at leaner air-fuel ratios and at higher turbocharging pressure is expected to decrease emissions of NOx because of lower combustion temperatures. Laser ignition systems have not been developed to the point where the effect of improved combustion chamber design can be measured. It is reasonable to expect that a better combustion chamber design would further decrease emissions of unburned hydrocarbons, carbon monoxide, and NOx. In actual operation of the engine, misfiring of one or more cylinders contributes to loss in efficiency and increase in emissions. With the laser ignition system, misfiring can be virtually eliminated. It is estimated that with laser ignited lean burn engines, the regulated levels of California Air Resources Board NOx levels can be met.

Economic

The primary advantage of laser ignition is its potential to eliminate downtime due to the need to change spark plugs. This advantage would accrue to both rich burn engines and lean burn engines. Higher efficiency due to near elimination of cylinder misfirings is an additional benefit.

Trade-offs

A tradeoff for engine manufacturers, assuming that laser ignition can be developed to the point of commercial feasibility, is whether or not to develop retrofit kits. Retrofits would be expected to take away sales of new engines.

A tradeoff for engine users is whether to continue using spark ignition or to purchase a laser ignition that is initially more expensive but has a future economic benefit.

Another tradeoff for engine users is whether to retrofit laser ignition to an existing engine or to spend more money for a new engine in return for future benefits.

II. Description of how to implement

A. Mandatory or voluntary: Implementation should be voluntary because the primary incentive for implementation is economic.
B. Indicate the most appropriate agency(ies) to implement: At the current state of development, a research organization is the best agency to develop laser ignition. After its feasibility is shown, an engine manufacturer, working with an ignition system supplier, is best equipped to carry the development through from product research to a commercial product.

III. Feasibility of the option

A. Technical: The primary technical risks are whether sufficiently high light flux can be carried through the fiber optic and whether the fiber optic is sufficiently durable. Laser ignition can be retrofitted to engines that use 18-mm spark plugs.
B. Environmental: If the technical barriers can be overcome, there is little environmental risk to laser ignition.
C. Economic: If the technical barriers can be overcome, the economic incentive for its adoption will depend on whether the engine must operate continuously or whether downtime can be scheduled to change spark plugs. The requirement for continuous operation favors laser ignition, which is expected to have a higher initial cost than spark ignition, but which can eliminate most of the

downtime for changing spark plugs.

IV. Background data and assumptions used TBD.

V. Any uncertainty associated with the option (Low, Medium, High) Medium to High

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups) TBD

2. Air-Separation Membranes

I. Description of the mitigation option

Overview

The purpose of air-separation membranes is to change the proportion of nitrogen to oxygen in air. A membrane can be optimized to either enrich the oxygen content or to enrich the nitrogen content. Both the oxygen enrichment mode and the nitrogen enrichment mode have been tested in the laboratory with diesel engines. The nitrogen enrichment mode has been tested in the laboratory with Natural Gas Fuel as well. The oxygen enrichment mode and the nitrogen enrichment mode are mutually exclusive.

Oxygen enrichment produces a dramatic reduction in particulate emissions at the expense of increased NOx emissions. However, Poola [***ref Poola paper***] has shown that the effects are non linear such that a small enrichment (1 percentage point or less) produces a significant reduction in particulate emissions with only a small increase in NOx emissions. By retarding the injection timing, one can achieve a reduction in both NOx and particulate emissions. The overall benefits of oxygen enrichment are relatively small, so it will not be considered further.
Nitrogen enrichment produces the same effect on emissions as exhaust-gas recirculation; NOx decreases while particulate emissions increase. Unlike diesel exhaust, the nitrogen enriched air does not contain particulate matter. Manufacturers of heavy-duty diesel engines are concerned that introducing particulate matter from EGR into the engine may cause excessive wear of the piston rings and cylinder liner. Thus, nitrogen enriched air is seen as an alternative to EGR. The published data in natural-gas engines show engine-out NOx reductions of 70% are possible with nitrogen-enriched combustion air. [Biruduganti, et al.]

Air Quality and Environmental Benefits

Oxygen-enriched air has only been demonstrated in the laboratory to be beneficial with one type of engine that is considered obsolete. Although the results are encouraging, further testing with a more modern engine would be necessary to confirm the decrease in both NOx and particulate emissions.

The development of oxygen-depleted air is further along and has been demonstrated as an effective alternative to EGR.

Economic

Use of oxygen-depletion membranes might have a higher initial cost than EGR, but would facilitate a longer interval between overhauls. It will have no adverse impact on engine wear or durability; however, EGR at high levels will have reduced engine durability.

Trade-offs

Engine manufacturers are concerned about the abrasive effects of particulate matter on piston rings and cylinder liners and other deleterious effects of EGR [830.pdf]. For the manufacturer the tradeoff is between the initial cost of an oxygen depletion membrane versus the higher frequency of overhauls required with EGR.

II. Description of how to implement

A. Mandatory or voluntary: Implementation should be voluntary because the primary incentive for implementation is economic.

B. Indicate the most appropriate agency(ies) to implement: The engine manufacturer is the appropriate agency to implement air separation membranes because the primary issue is initial cost versus frequency of overhauls.

III. Feasibility of the option

A. Technical: The technical feasibility of oxygen-depletion membranes has been demonstrated as an alternative to EGR. The technical feasibility of oxygen-enrichment membranes has only been shown in the laboratory for one type of engine. The technical advantages of nitrogen enrichment with membranes have been demonstrated in the laboratory for natural gas and diesel engines.

B. Environmental: The environmental benefits of oxygen-depletion membranes are the same as EGR.

C. Economic: Membrane manufacturers are presently unable to produce enough membranes for widespread implementation of the technology in truck engines. However, the oil and gas industry is a smaller market, which might allow the membrane manufacturers to ramp up their production levels. Because of this situation, the economic feasibility of air-separation membranes is difficult to assess.

IV. Background data and assumptions used

www.enginemanufacturers.org/admin/library/upload/830.pdf

Published technical papers by Argonne National Laboratory and others.

V. Any uncertainty associated with the option (Low, Medium, High)

Low to medium. The technology would receive a "low" uncertainty rating if the availability issue were more settled.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups) TBD

3. Rich-Burn Engine with Three-Way Catalyst

I. Description of the mitigation option

Overview

Rich-burn engines with a three-way catalyst borrow from the well developed automobile technology using the same type of catalyst. Key to efficient operation of the catalyst is maintenance of slightly lean of stoichiometric operation of the engine. Typically the exhaust oxygen content is maintained in a narrow range not exceeding 0.5% by means of an oxygen sensor in the exhaust stream and closed-loop feedback control of the fuel flow. The oxygen content is enough to catalytically oxidize carbon monoxide and unburned hydrocarbons as it chemically reduces NOx to molecular nitrogen and water. If the engine is operated lean of its desired operating point, NOx reduction efficiency drops off dramatically. If operation is rich, emissions of carbon monoxide and unburned hydrocarbons increase.

It is commercially available as a retrofit for smaller engines. Larger engines are usually operated in the lean-burn mode.

Air Quality and Environmental Benefits
Air quality benefits would be similar to automobiles, where catalytic converters are universally used with rich burn engines.

Economic
Cost of three-way catalyst systems is considered high, but less than that of SCR with a lean-burn engine.

Trade-offs
For small engines (that is, less than 200 BHP) lean burn technology may not be available. Where there is a choice of rich-burn or lean-burn engines, the lean-burn engines offer better fuel economy and more effective, albeit more expensive, overall emissions control via SCR and oxidation catalysts.

II. Description of how to implement

A. Mandatory or voluntary: The use of three-way catalysts will be dictated by the stringency of emissions regulations. Three-way catalysts are sufficiently expensive that they are not likely to be adopted voluntarily.
B. Indicate the most appropriate agency(ies) to implement: U.S. EPA and state agencies

III. Feasibility of the option

A. Technical: The technology is commercially available and has been proven effective. Rich-burn engines have higher engine-out NOx emissions, typically about 10-20 g/BHP-hr [830.pdf and reportoct31.doc], than lean-burn engine have. This requires the removal of at least 95% of the NOx if overall emissions are to be reliably reduced to less than 1 g/BHP-hr.
B. Environmental: The State of Colorado estimates that a 3-way catalyst can remove 75% of the NOx, unburned hydrocarbons, and carbon monoxide [reportoct31.doc, although manufacturers of equipment claim that 98-99% of these pollutants are removed.
C. Economic: The State of Colorado estimates that the cost of retrofitting a three-way catalyst system to a rich-burn engine over 250 BHP is $35,000 with annual operating costs of $6,000 [reportoct31.doc].

IV. Background data and assumptions used

http://apcd.state.co.us/documents/eac/cd2/reportoct31.doc

www.enginemanufacturers.org/admin/library/upload/830.pdf

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups TBD

4. Lean-Burn NOx Catalyst, Including NOx Trap

I. Description of the mitigation option

Overview

Lean-burn NOx catalysts have been under development for at least two decades in the laboratory with the intent of producing a lower cost alternative to SCR.

Several variants of lean-burn NOx catalysts have been studied: (1) Passive lean-burn NOx catalysts simply pass the exhaust over a catalyst. The difficulty has been low NOx conversion efficiency because the oxygen content of a lean-burn exhaust works against chemical reduction of NOx. Conversion efficiencies of the order of 10% are typical [park.doc.

(2) Active lean-burn NOx catalysts use a fuel as a reductant. The catalyst decomposes the fuel, and the resulting fuel fragments either react with the NOx or oxidize. Methane is much more difficult to decompose than heavier fuels, such as diesel [aardahl.pdf. A wide range of NOx reduction efficiencies from 40% to more than 80% have been published [park.doc and icengine.pdf]. Variants of active lean-burn catalyst systems may use plasma or a fuel reformer to produce a more effective reductant than neat fuel [aardahl.pdf, 2003_deer_aardahl.pdf, and 80905199.htm].

(3) NOx trap catalysts are a more recent development that has seen some laboratory success. Operation is a two-step cyclic process. In the first stage the NOx trap adsorbs NOx while the engine operates in a lean-burn mode. In the second stage, the engine operates with excess fuel in the exhaust. The fuel decomposes on the catalyst and reduces the NOx to molecular nitrogen and water. When the supply of trapped NOx is exhausted, the system reverts back to first-stage operation. NOx reduction efficiencies in excess of 90% have been published [parks01.pdf. A sophisticated engine control is required to make this system work.

Air Quality and Environmental Benefits

NOx traps have been proven to be effective and have seen some limited commercial success in Europe. NOx traps are one of the reasons for the dramatic reduction in sulfur content of diesel fuel in the U.S. Fuel-borne sulfur causes permanent poisoning of NOx-trap catalysts. There are doubts regarding the NOx conversion efficiency levels after 1,000 hours or longer use. This should be evaluated, as well as the durability of the equipment.

Active lean-NOx catalysts have seen limited commercial success because they are less effective than NOx traps and are not being considered for on-road diesel engines. Some instances of formation of nitrous oxide (N2O) rather than complete reduction of NOx have been reported.

Passive Lean-NOx catalysts do not provide enough NOx reduction to be considered viable.

Economic

Costs of retrofitting a lean-burn NOx catalyst are estimated at $6,500 to $10,000 per engine [retropotentialtech.htm], $15,000-$20,000 including a diesel particulate filter [V2-S4_Final_11-18-05.pdf] for off-road trucks. Estimates are $10-$20/BHP for stationary engines [icengine.pdf].

Little information on the cost of NOx-trap catalytic systems was found. The overall complexity of a NOx-trap system is only slightly more than that of a lean-burn NOx catalyst, so costs can be expected to be slightly higher. With methane-burning engines, both active lean-burn NOx catalysts and NOx-trap catalysts require a fuel reformer or other means of dissociating methane. This will add an increment of cost.

Both active lean-NOx technology and NOx-trap technology impose a fuel penalty of 3-7%.

Trade-offs

NOx-trap systems compete with SCR systems. For methane-burning engines, a fuel reformer is required for NOx-trap systems. Fuel reformers are less well developed.

If emissions regulations can tolerate higher NOx emissions, an active lean-burn NOx catalyst might be considered.

I. Description of how to implement

A. Mandatory or voluntary: The costs of lean-burn NOx catalysts and NOx traps are such than voluntary compliance is unlikely. However, depending on the strictness of the regulations, the user may have a choice of systems.
B. Indicate the most appropriate agency(ies) to implement: U.S. EPA and state agencies.

II. Feasibility of the option

A. Technical: NOx-trap systems are proven and commercially available for diesel engines. However, they require low-sulfur diesel fuel (less than 15 ppm) to minimize sulfur poisoning of the catalyst. Active lean-burn catalysts are available, but they have a lower NOx reduction efficiency than NOx-trap systems have. Both the lean-burn NOx catalyst and the NOx trap requires a fuel reformer (which can be a catalyst stage upstream of the NOx catalyst) to operate at full efficiency with natural-gas fueled engine.
B. Environmental: Lean-burn NOx catalysts and NOx-trap catalysts do not have the ammonia slip issue that SCR systems have, but lean-burn NOx catalysts may only partially reduce some of the NOx to nitrous oxide (N2O). The NOx reduction efficiency of NOx traps is similar to that of SCR systems (>90%), but active lean-burn NOx catalysts have a lower efficiency (40-80%).
C. Economic: Lean-burn NOx catalysts and NOx traps have lower costs than SCR and they avoid the need to purchase and maintain a separate reductant. However, both lean-burn NOx catalysts and NOx traps impose a fuel consumption penalty of 3-7%.

III. Background data and assumptions used

Abstract of Caterpillar paper found at www.emsl.pnl.gov/new/emsl2002/abstracts/park.doc.

www.meca.org.galleries/default-file/icengine.pdf

www.energetics.com/meetings/recip05/pdfs/presentations/aardahl.pdf

www.eere.energy.gov/vehiclesandfuels/pdfs/deer_2003/session10/2003_deer_aardahl.pdf

www.swri.org/epubs/IRD1999/08905199.htm

www.feerc.ornl.gov/publications/parks01.shtml

www.epa.gov/oms/retrofit/retropotentialtech.htm

www.wrapair.org/forums/msf/projects/offroad_diesel_retrofit/V2-S4_Final_11-18-05.pdf

IV. Background data and assumptions used None

V. Any uncertainty associated with the option (Low, Medium, High)

NOx traps have a low uncertainty if they are used with low sulfur diesel fuel. They have a medium uncertainty when used with natural gas because of the need to reform the fuel.

Lean-burn NOx catalysts have a medium uncertainty because they may not be able to meet future emissions regulations.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups
To be determined. The issue of incomplete NOx reduction that leaves some nitrous oxide (N2O) may be moot if active lean-burn NOx catalysts cannot meet future emissions regulations.

5. Homogeneous-Charge Compression-Ignition (HCCI) Engine

I. Description of the mitigation option

Overview

Homogeneous charge compression ignition (HCCI) engines are under development at several laboratories. In these engines a fully mixed charge of air and fuel is compressed until the heat of compression ignites it. The HCCI combustion process is unique since it proceeds uniformly throughout the entire cylinder rather than having a discreet high-temperature flame front as is the case with spark ignition or diesel engines. The low-temperature combustion of HCCI produces extremely low levels of NOx. The challenge of HCCI is in achieving the correct ignition timing, although progress is being made in the laboratories.[1]

Only a few experimental measurements of NOx from (HCCI) engines have been reported. The measurements are typically reported as a raw NOx meter measurement in parts per million rather than being converted to grams per horsepower-hour. Dibble reported a baseline measurement of 5 ppm when operated on natural gas.[2] Green reported NOx emissions from HCCI-like (not true HCCI) combustion of 0.25 g/hp-hr.[3] The achievable NOx emission levels are yet to be determined. It is not currently known if HCCI technology can be applied to all engine types and sizes. However, if all reciprocating engines could be converted to HCCI so that the engines produce no more than 0.25 g/hp-hr, then the overall NOx emissions reduction would be 80% in both Colorado and New Mexico using the calculation methodology of the SCR mitigation option.

II. Description of how to implement

A. Mandatory or voluntary: It is too early to determine whether implementation of this technology will be voluntary or mandatory.
B. Indicate the most appropriate agencies to implement

III. Feasibility of the option

A. Technical: HCCI is in the laboratory stage of development.

B. Environmental: HCCI has the potential of extremely low NOx levels.

C. Economic: HCCI is not sufficiently developed to have proven economic feasibility.

IV. Background data and assumptions used

1. Bengt Johansson, "Homogeneous-Charge Compression-Ignition: The Future of IC Engines," Lund Institute of Technology at Lund University, undated manuscript.

2. Robert Dibble, et al, "Landfill Gas Fueled HCCI Demonstration System," CA CEC Grant No: PIR-02-003, Markel Engineering Inc.

3. Johney Green, Jr., "Novel Combustion Regimes for Higher Efficiency and Lower Emissions," Oak Ridge National Laboratory, "Brown Bag" Luncheon Series, December 16, 2002.

V. Any uncertainty associated with the option (Low, Medium, or High)

HCCI has high uncertainty.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups (Please describe the issue and which group.)

Summary

Five technologies are reported: laser ignition, air-separation membranes, rich-burn engine with three-way catalyst, lean-burn NOx catalyst, and Homogeneous-Charge Compression-Ignition (HCCI) Engine.

Laser ignition is not presently a commercial product. The impetus for investigating it is the potential to eliminate the need for changing spark plugs. It will also allow operation at leaner air-fuel ratios, higher compression ratios, and higher turbocharging pressure. Leaner air-fuel ratios imply lower engine-out NOx emissions so the after treatment can be smaller or can give lower overall emissions. Higher compression ratios and turbocharging ratios imply higher engine efficiency.

Air-separation membranes used to deplete oxygen from the combustion air can serve as a clean replacement for EGR. That is, an engine using oxygen-depleted air would not be ingesting combustion products. Engine manufacturers are concerned that EGR will shorten the life of their engines and lead to premature overhauls and warranty repairs. The technology has been demonstrated in the laboratory, but has not been used for heavy-duty trucks because membrane manufacturers do not have enough production capacity for the market. Stationary engines are a smaller market, so the membrane manufacturers may be able to ramp up their capacity with stationary engines. Applicability is to diesel engines and rich-burn natural-gas engines. Oxygen-depletion membranes have not been tested with lean-burn natural-gas engines.

A rich-burn engine with a three-way catalyst is a mature technology that is borrowed from automobile engines. The three-way catalyst effectively control NOx, unburned hydrocarbon, and carbon monoxide emissions. It requires an exhaust oxygen sensor with a closed-loop control of the fuel so that exhaust oxygen is maintained in a narrow range not exceeding 0.5%. It can be retrofitted to existing engines and is primarily applicable to small engines for which lean-burn combustion is not available. Its primary disadvantages are cost and the inherently lower efficiency of rich-burn engines compared to lean-burn engines.

Lean-burn NOx catalysts have several forms, but the one that is of most interest is the NOx-trap catalyst. Unlike SCR, lean-burn NOx catalysts use the engine's fuel as a reductant and do not require a separate supply of reductant. It is a well proven in the laboratory and is commercially available in Europe for diesel engines, but it requires a fuel reformer if natural gas is used as the reductant. A sophisticated control system is required to cycle the engine between its two modes of operation. Ammonia slippage is not an issue with NOx traps, and if there is any slippage of unburned fuel it can be removed with an oxidation catalyst. Cost is high but less than that of SCR systems. A disadvantage of NOx traps is that they are intolerant of fuel-borne sulfur. For diesel fuel, the sulfur content must be less than 15 ppm. Fuel-borne sulfur permanently poisons the catalyst. Since fuel is used as a reductant, there is a fuel consumption penalty of 3-7%.

ENGINES: MOBILE/NON-ROAD

Mitigation Option: Fugitive Dust Control Plans for Dirt/Gravel Road and Land Clearing

I. Description of the mitigation option
Fugitive dust emissions from traffic on dirt roads and construction sites are a nuisance and cause frequent complaints. Health concerns related to PM 10 (particulate matter less than 10 microns in size) exposure to high concentrations are breathing, aggravated existing respiratory and cardiovascular disease, lung damage, asthma, chronic bronchitis, and other health problems. Adequate measures could include wind breaks and barriers, water or chemical applications, control of vehicle access, vehicle speed restrictions, gravel or surfacing material use, and work stoppage when winds exceed 20 miles per hour. Activities occurring near sensitive and/or populated areas should receive a higher level of preventive planning. Sensitive receptors would include schools, housing, and business areas.

Economic burdens include increase business costs associated with increased road maintenance, loss of time and productivity associated with work stoppage during high wind days, and increased travel times due to speed restrictions. However, reduced wear on roads and vehicles may be recognized through vehicle speed restrictions.

II. Description of how to implement
A. Mandatory or voluntary: Speed restrictions, regular road maintenance, and construction activity restrictions during high wind days would be mandatory. Road surfacing, wind breaks and barriers and vehicle access control would be voluntary.
B. Indicate the most appropriate agency (ies) to implement: The states, tribal governments, BLM, FS, County, and Industry.

III. Feasibility of the option
A. Technical: The current BLM Road committee is a functional working group with 13 road maintenance units. An industry representative is assigned to each unit to oversee road construction and maintenance activities through a cost-sharing program. BLM law enforcement along with county and state law enforcement could enforce speed restrictions. Industry could make observing speed limits a company policy. Conditions of approval could be added to permitted activities to restrict surface disturbing activities during high wind days. However, industry would prefer the use of other mitigation measures such as road surface treatments (e.g. fresh water or special emulsion) during high wind days.

B. Environmental: The environmental benefits from regular and proper road maintenance, speed restrictions, and surface disturbing activities during high wind days are well documented.

C. Economic: Cost sharing is an important purpose of the current roads committee that is very active and functional work group with regularly scheduled meetings. Funding for speed enforcement is an intricate part and regularly funded operation of BLM, county and state law enforcement.

IV. Background data and assumptions used
1. BLM Gold Book-Surface Operating Standards for Oil and Gas Exploration and Development.
2. Numerous studies on road related erosion issues and standards exist.
3. Studies on excessive road speed and dust development.

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option
Four member drafting team support this option

VII. Cross-over issues to the other source groups None at this time.

Mitigation Option: Use Produced Water for Dust Reduction

I. Description of the mitigation option

This option involves using produced water on roads for dust suppression. Large volumes of water are often produced in conjunction with natural gas production, especially coal bed methane (CBM) production. Wells often produce up to 100-400 barrels/day. CBM produced water quality ranges from nearly fresh water to well above 10,000 ppm total dissolved solids (TDS) and is readily available as an option for road dust suppression. The produced water used for dust mitigation would have to have low TDS and low sodium levels that meet BLM and county standards. Some CBM water meets these standards but not all of it.

Economic benefits could be realized by oil and gas operators in reduced trucking and disposal costs. Likewise, there are associated environmental benefits to this reduced trucking as is outlined in another mitigation strategy. However, the use would be as needed and seasonal (during prolonged dry periods or drought).

Environmental concerns and issues would arise concerning 1) salt build up along roadways, 2) migration of water and associated pollutants off the roadway, 3) impacts to vegetations, 4) salt loading to river systems.

Differing Opinion: Produced water in the Four Corners region contains toxins and therefore should not be used for dust mitigation. The potential environmental concerns include more than just salt-related impacts. Produced waters are of variable quality. Depending on the source, the water may contain high concentrations of constituents other than salts. Data on produced water quality is not widely available to the public. One example of produced water quality, however, was published in a recent report prepared with support from the U.S. Department of Energy. The data show that in the New Mexico portion of the San Juan Basin, there can be elevated concentrations of various metals and other constituents in produced water (in addition to elevated salts – those data not shown).[1]

	McGrath SWD[2]		**Four CBM injection wells[3]**	
All values in mg/L	**Max**	**Min**	**Max**	**Min**
Barium	8.0	0.72	23.9	1.86
Boron	3.0	1.0	2.87	1.6
Bromium	21.8	7.1	15.2	2.4
Copper	0.019	ND		
Chromium	0.035	ND	0.005	
Iron (dissolved)[4]	187	1.1	0.843	0
Selenium	0.080	ND	0.0171	ND

[1] DiFilippo, Michael N. August, 2004. Use of Produced Water in Recirculating Cooling Systems at Power Generating Facilities. Semi-Annual Technical Progress Report October 1, 2003 to March 31, 2004. Report produced with support from U.S. Department of Energy, Award No. DE-FC26-03NT41906. pp. 12-3.

[2] McGrath Saltwater Disposal Well (SWD): data were from a 30 day random sampling of the SWD well), which was operated by Burlington (now, presumably Conoco).

[3] CBM SWD wells operated by Dugan (Salty Dog 2 and 3 Injection Wells) and Richardson (Turk's Toast and Locke Taber Injection Wells).

[4] According to DiFilippo (page 10), most of the iron comes from aboveground carbon steel pipe used to convey produced water. So, presumably, if water were applied from trucks getting water from the well site, itself, this would not be a concern. If it were water being loaded at the SWD facility, then the iron would be present.

Silver			0.20	ND
Strontium	55	7.2	34.5	1.73
Lead	0.031	ND	0.1	
Total Petroleum Hydrocarbons (TPH)	520	23	17	ND
Zinc			0.298	ND

* ND is non-detected

Produced water may also contain chemical additives put downhole during the drilling, stimulation or workover of the wells. Some of these treatment chemicals, such as biocides, can be lethal to aquatic life at levels as low as 0.1 part per million.[5] It is very difficult to obtain information on the concentrations of treatment chemicals and additives in produced water.

Environmental Justice Issues: Only with the permission of surface owners, municipalities, counties, etc. should produced water be applied to roads. And these entities should be provided with produced water quality information prior to road spreading.

Wyoming requires landowner consent prior to road spreading, which is an important provision to ensure that surface owners have a say in the application of large quantities of water that could affect their property. In Pennsylvania, other jurisdictions, such as municipalities, also have a say with respect to whether or not road spreading is allowed.[6]

II. Description of how to implement

A. Mandatory or voluntary: The use of produced water would be voluntary; however, ultimate approval to do so would be up to the state authority that has primacy over the disposal and use of produced water.
B. Indicate the most appropriate agency(ies) to implement: OCD, BLM, FS.

It may also be necessary to include the states in the implementation of any permitting process related to road spreading since these agencies have the expertise and develop the environmental standards related to surface and groundwater pollution. There is a precedent for involving environment departments. In Wyoming, although the Oil Conservation Commission is responsible for permitting road spreading applications, the operations must also be approved by their Department of Environmental Quality.[7]

III. Feasibility of option

A. Technical: This option is technically feasible, but would require strict controls and monitoring. "Because of the potential for contaminants from the brine to leach into surface or ground waters, the Department of Environmental Protection (DEP) has developed guidelines that must be followed when spreading brine on unpaved roads."[8] It would be advisable for the responsible agencies to develop their

[5] Argonne National Laboratory. January, 2004. A White Paper Describing Produced Water from Production of Crude Oil, Natural Gas and Coalbed Methane. Prepared for U.S. Department of Energy. Contract No. W-31-109-Eng-38.
[6] http://www.dep.state.pa.us/dep/deputate/minres/oilgas/fs1801.htm
[7] Rules and Regulations of the Wyoming Oil and Gas Conservation Commission
Chapter 4, Section 1 http://www.cbmcc.vcn.com/dust.htm
"(nn) Landfarming and landspreading must be approved by the DEQ. Jurisdiction over roadspreading or road application is shared by DEQ and the Commission. . ."
[8] http://www.dep.state.pa.us/dep/deputate/minres/oilgas/fs1801.htm

own guidelines or policies to ensure that road spreading practices are carried out in an environmentally sound manner.

B. Environmental: Would require constraints on the allowable TDS and/or SAR content of the water and volumes applied. Baseline field testing for migration/movement would be required to determine if salt build-up is occurring. The use of boom type sprayer (i.e. spreader bars) to prevent pooling and washing off of roadway needs to be highly considered. A responsible party on site during application would be necessary and signage indicating road maintenance being conducted.

Most jurisdictions that allow road spreading do not require chemical data on anything but the salts or dissolved solids (TDS). While TDS includes constituents such as dissolved metals, it does not provide any specific information as to the concentrations of the various metals. Basing the acceptability of using produced water for road spreading on salt content or TDS overlooks the potential impacts from other produced water constituents like metals, hydrocarbons, treatment chemicals and radionuclides (e.g., strontium).

Prior to application of produced water for road spreading purposes, it would be prudent to analyze the water for all potentially harmful constituents. In 2000, there was a case in Garfield County, CO, where a company illegally spread flowback fluids from a workover operation. Samples of the produced water subsequently showed that TDS levels and BTEX were above state drinking water standards.[9]

Prohibit spreading of flowback water. In Pennsylvania, operators are not allowed to spread produced water that main contain treatment chemicals. "Only production or treated brines may be used. The use of drilling, fracing, or plugging fluids or production brines mixed with well servicing or treatment fluids, except surfactants, is prohibited. Free oil must be separated from the brine before spreading." Essentially, this would mean that the operator would have to wait a certain period of time to allow the majority of the treatment chemicals to flow out of the well before using the produced water for road spreading purposes.

C. Economic: Some operators may see a reduction in hauling and trucking cost associated using produced water for dust control.

IV. Background data and assumptions used

1. Currently produced water is used in some areas for road reconstruction and maintenance, but not for dust reduction. Current levels allowed are 5,000 TDS for maintenance and 18,000 TDS for reconstruction.
2. Could consider higher TDS levels of use with tight restriction on applications methods and timing.
3. Assume applications would be seasonal (during summer dry months)
4. Restricted to main collector road or on all roads with high traffic flow.
5. Need to protect operator's investment for roadwork already completed.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium uncertainty to environment (water quality and vegetation).

VI. Level of agreement within the work group for this mitigation option.

All members of drafting team support this option.

VII. Cross-over issues to other source groups None at this time.

[9] Colorado Oil and Gas Information System. 7/6/2000. Notice of Alleged Violation Report. Barrett Resourced Corp. Document No. 850224. http://oil-gas.state.co.us/cogis/NOAVReport.asp?doc_num=850224

Mitigation Option: Pave Roads to Mitigate Dust

I. Description of the mitigation option
This option involves paving roads that service the vast amounts of oil and gas locations in the four corners region. The benefits to air quality would be a significant reduction in dust generated by traffic in the San Juan Basin. Consideration should be given to paving only those collector roads that are located near populated areas and those that received heavy traffic and excessive dust because of high cost of paving. Currently a pilot project is being proposed to use hot emulsified asphalt on reconstructed collector roads. The hot asphalt would be incorporating it into the sandstone caps material using a road re-claimer or blade in an effort to create a durable driving surface.

Economic burdens would be extreme costs to oil and gas operators, federal, state and local governments associated with paving and maintaining a vast network of roads in the San Juan Basin. There would be an immediate increase in traffic accidents associated with an eminent increase in speed associated with paved roads.

II. Description of how to implement
A. Mandatory or voluntary: The construction and road base preparation necessary to properly pave a road would be voluntary
B. Indicate the most appropriate agency(ies) to implement: Industry, OCD, BLM, FS, County, State.

III. Feasibility of option
A. Technical: This option is technically feasible but not practical to pave all roads. Consideration needs to be given to highly travel collector roads and road near heavily populated areas. Portions of heavily travel roads could be considered for paving.
B. Environmental: Would reduce long term dust emissions from vehicle traffic throughout the San Juan Basin but there would be some shorter term increases in emissions associated with asphalt production, paving, and the construction equipment paving the road itself. However, increase accidents and speeding could be drawbacks. Additional law enforcement would be required or re-prioritized workload to curtail speeding.
C. Economic: The cost to prepare, pave, and maintain roads throughout the San Juan Basin are not practical on all roads. Furthermore, the cost to reclaim "paved roads" as part of the restoration process upon well abandonment would be substantial. Consideration could be give to paving only portions of main collector roads, especially in populated areas with heavy traffic.

IV. Background data and assumptions used
1. Pilot project currently proposed. Need to evaluate the effectiveness of using hot emulsified asphalt. Not practical to pave all roads in the San Juan Basin.
2. Restricted to main collector road with heavy traffic, dust problems, and populated areas.
3. Would require addition capital outlay and cost sharing.

V. Any uncertainty associated with the option (Low, Medium, High)
High, due to cost and feasibility.

VI. Level of agreement within the work group for this mitigation option.
Members agree that this option has some merit but in limited areas. Not practical to consider the entire San Juan Basin.

VII. Cross-over issues to other source groups None at this time.

Mitigation Option: Automation of Wells to Reduce Truck Traffic

I. Description of the mitigation option

This mitigation option would involve equipping wells with a variety of technology for the ultimate purpose of being able to decrease traffic to well sites when everything is operating normally. The potential air quality benefits include reduced dust and tailpipe emissions from vehicle traffic. Other potential environmental benefits include reduced vehicular fuel consumption (and therefore the need for crude oil feedstocks). Economically, the energy companies could benefit by reducing their workforces and the expenses paid for contractors. As this automation may require the electrification of the equipment, the air quality benefits may be offset by emissions elsewhere and of a different nature. Costs for implementing this option may entail the installation of massive electrification systems to power the sensors, radios, and automated valves (vista issues). Additionally, should every well not be checked on a daily basis, there is believed to be a high likelihood that leaks small enough to be undetectable by the automation sensors could go on unabated until the next time the well was visited. This would represent a real tradeoff of risk (air quality vs. soil / water impact). Significant burden would fall on the operator in such a situation. An additional benefit of this option is that once electricity is available at the site, it would increase the feasibility of the electric compressor option included under Stationary RICE.

II. Description of how to implement

The oil & gas industry already uses automation technology where technically and economically feasible. Therefore, this mitigation option would best be implemented in a voluntary manner. As such, agency involvement would not be required.

III. Feasibility of the option

A. Technical: The technology exists today to implement this mitigation option.
B. Environmental: A study would need to be made to determine the relative benefit of reducing emissions at the well site but increasing emissions during electrification and offsite power generation. (Cumulative Effects Work Group task?)
C. Economic: In some cases the implementation of this technology is economically feasible. In many others it is not. Forced implementation could very well hasten the uneconomic status of a well resulting in the premature abandonment of the well and its hydrocarbon products.

IV. Background data and assumptions used

While EPA does have AP-42 emission factor data available for unpaved roads (13.2.2), no input information was available in the time frame desired to make any calculations / determinations, hence the high-level and qualitative analysis. (Cumulative Effects Work Group task?)

V. Any uncertainty associated with the option

High. The feasibility of implementing this option is very situation specific. It is believed that widespread implementation (75% of wells) is probably not feasible.

VI. Level of agreement within the work group for this mitigation option

Subgroup is in agreement with this option.

Cross-over issues to the other source groups

None at this time.

Mitigation Option: Reduced Vehicular Dust Production by Enforcing Speed Limits

I. Description of the mitigation option

This mitigation option would involve enforcing speed limits on unpaved roads in an attempt to reduce dust emissions. The potential air quality benefits include reduced dust emissions from slowed vehicle traffic. Another potential environmental benefit (albeit marginal) is reduced vehicular fuel consumption (and therefore the need for crude oil feedstocks). Economically, although theoretically less work would be accomplished in the same time period, this impact would be insignificant since the degree of excess over the speed limit is probably not such that implementation of this mitigation strategy would make a significant difference.

A. Public Roads: Enforcement on public roads would be most easily accomplished using local law enforcement agencies. Costs for stepping up enforcement of the speed limits on public roads might include additional funds for increased staff for the local law enforcement agencies.

B. Private Roads: To the extent the unpaved roads are private, the setting and enforcing of speed limits would have to take place in a cooperative agreement between local landowners and energy companies. Since energy companies are not staffed, trained or equipped to be law enforcement agents, this would represent a significant cost shift to the energy companies. Costs for implementing this option on private roads would entail legal review to understand on what basis such" private law enforcement" could take place, the negotiating of agreements with landowners, the posting of signs, and the staffing, training, and equipping of workers to fulfill this function.

C. Assistance: Cumulative Effects work group would be needed to understand the relative benefit of reduced speed on dust production.

II. Description of how to implement

A. On public unpaved roads, enforcement of existing speed limits could be seen as mandatory. The most appropriate agencies to implement are the existing local law enforcement agencies.

B. On private roads, implementation would have to be voluntary as no agency can force a landowner to undertake such a proposition. It is not appropriate for any agencies to get involved in the implementation of this mitigation option. It would be most appropriate for the environmental agencies to simply recognize this as a bona fide emission reduction strategy, and then let the energy company determine where and when to implement such a strategy.

III. Feasibility of the option

A. Technical – Greater enforcement of speed limits on public unpaved roads would be feasible. Establishing and enforcing speed limits on private unpaved roads is feasible but less so.

B. Environmental - Assistance from the Cumulative Effects work group would be needed to understand the relative benefit of reduced speed on dust production (how much reduction in speed is needed to have a significant reduction of dust?).

C. Economic - Assistance from the Cumulative Effects work group would be needed to understand the relative economic benefit of reduced speed on dust production.

D. Public Perception – This could be an issue based on the assumption that most people would want any additional funding for police activities to go toward safety/crime issues.

IV. Background data and assumptions used

While EPA does have AP-42 emission factor data available for unpaved roads (13.2.2), no input information was available in the time frame desired to make any calculations / determinations. Hence the high-level and qualitative analysis in this option paper. The governing equations do however include speed as a component.

V. Any uncertainty associated with the option

High. Assistance from the Cumulative Effects work group would be needed to understand the relative economic benefit of reduced speed on dust production. Once that is understood, an analysis could be made to reduce the economic and regulatory uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups

It is believed that this issue will cross-over to the Other Sources group.
Could the issue described in IV above be addressed by the Cumulative Effects work group?

Mitigation Option: Reduced Truck Traffic by Centralizing Produced Water Storage Facilities

I. Description of the mitigation option

This mitigation option would involve reducing vehicular traffic on unpaved roads (and hence dust production) by centralizing produced water storage facilities and pumping water to them. Much of the large truck traffic on unpaved lease roads is water haulers. Therefore, one strategy to reduce dust is to reduce water hauler traffic. However, unless the produced water could be piped directly to the disposal (injection well) location, the same volume of truck traffic would exist. Therefore, to reap the benefits from this strategy, it would be necessary to either pipe the water directly to the disposal location, or to site the centralized produced water storage facility along a paved road such that the water transporters would not be driving on unpaved roads and creating dust.

Benefits from this strategy include dust reduction, vehicle tailpipe exhaust emission reduction (potential), reduced road maintenance, and marginally safer roads. Burdens would fall exclusively on the energy companies. These burdens would include obtaining rights-of-way to lay the needed pipelines, securing the pipe, securing trenching and installation services, and paying crews to make the necessary tie-ins. As much of the produced water in southern Colorado is essentially fresh in nature, heat tracing may be needed to prevent the freezing and bursting of pipes.

Tradeoffs would include the pollutants emitted at the source of the power used to drive the transfer pumps. This power production could be either at the well location (natural gas fired) or at the power plant (electric). Additionally, the dust emissions are currently dispersed over a large area. Centralizing storage would greatly increase tailpipe emissions locally and potentially produce local air quality, noise, and traffic safety issues. Additionally, aggregating produced water in one location increases the potential for a catastrophic release. This would represent a real tradeoff of risk (air quality vs. soil / water impact). Additional tradeoffs include the emissions produced at the point of pipe manufacture and the emissions from the trenching operations. Assistance is needed from the Cumulative Effects work group to estimate the net air quality gain from centralizing produced water storage facilities.

II. Description of how to implement

A. This mitigation option should be implemented on a voluntary basis. Forced implementation could hasten the uneconomic status of groups of wells resulting in premature abandonment of the wells and their hydrocarbon products.
B. The most appropriate agency to implement would be the environmental agency through permitting incentives/offsets. It would be necessary to first understand the relative benefit of reducing emissions from lease road traffic but increasing emissions elsewhere (Cumulative Effects Work Group task).

III. Feasibility of the option

A. Technical: The technology exists today to implement this mitigation option.
B. Environmental: A study would need to be made to determine the relative benefit of reducing emissions from lease road traffic but increasing emissions elsewhere (Cumulative Effects Work Group task).
C. Economic: In some cases the implementation of this technology will be economically feasible. In many others it will not be.

IV. Background data and assumptions used:

While EPA does have AP-42 emission factor data available for unpaved roads (13.2.2), no input information was available in the time frame desired to make any calculations / determinations. Hence the high-level and qualitative analysis. This could be a Cumulative Effects Work Group task.

V. Any uncertainty associated with the option (Low, Medium, High):
High. Assistance from the Cumulative Effects work group would be needed to understand the relative economic benefit of reduced truck traffic vs. laying miles of pipelines and setting many pumps. Once that is understood, an analysis could be made to reduce the economic and regulatory uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option

V. Cross-over issues to the other source groups
It is believed that this issue will not cross-over to any other source work group. Assistance from the Cumulative Effects work group on the issue in V. above would be helpful.

Mitigation Option: Reduced Vehicular Dust Production by Covering Lease Roads with Rock or Gravel

I. Description of the mitigation option

This mitigation option would involve reducing vehicular dust production by covering unpaved roads with rock or gravel. Benefits from this strategy include only dust reduction. Burdens would fall exclusively on the energy companies. These burdens would include obtaining the road material and paying crews to install it. Additionally, the presence of rock on the roads makes snow removal more difficult, and is hard on snow removal equipment. Therefore, road maintenance costs may increase during the winter months. Tradeoffs would include the pollutants emitted during the trucking and installation of the road material. Assistance is needed from the Cumulative Effects work group to estimate the net air quality gain from centralizing produced water storage facilities.

II. Description of how to implement

A. This mitigation option should be implemented on a voluntary basis. Forced implementation could hasten the uneconomic status of groups of wells resulting in premature abandonment of the wells and their hydrocarbon products.

B. The most appropriate agency to implement would be the environmental agency through permitting incentives/offsets. It would be necessary to first understand the relative environmental benefit of covering roads with rock (Cumulative Effects Work Group task).

III. Feasibility of the option

Technical – The technology exists today to implement this mitigation option.

Environmental – A study would need to be made to determine the relative emission reductions due to covering the roads with rock (Cumulative Effects Work Group task).

Economic – In some cases the implementation of this technology will be economically feasible. In others it will not be.

IV. Background data and assumptions used

While EPA does have AP-42 emission factor data available for unpaved roads (13.2.2), no input information was available in the time frame desired to make any calculations / determinations. Hence the high-level and qualitative analysis. (Cumulative Effects Work Group task?)

V. Any uncertainty associated with the option (Low, Medium, High)

High. Assistance from the Cumulative Effects work group would be needed to understand the relative emission reduction benefit from covering lease roads with rock. Once that is understood, an analysis could be made to reduce the economic and regulatory uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups (please describe the issue and which groups

It is believed that this issue may cross-over to the Other Sources work group.

Mitigation Option: Reduced Truck Traffic by Efficiently Routing Produced Water Disposal Trucks

I. Description of the mitigation option

This mitigation option would involve setting up a produced water hauler coordinating / dispatch service to route water haulers as efficiently as possible in order to reducing vehicular traffic on unpaved roads (and hence dust production). Much of the large truck traffic on unpaved lease roads is water haulers. Therefore, one strategy to reduce dust is to minimize water hauler traffic. To accomplish this goal, it would be necessary institute a central dispatch concept among all of the water haulers in the area such that (a) only full truckloads are hauled from a given area and (b) the water is hauled to the closest disposal facility possible. Benefits from this strategy include dust reduction, vehicle tailpipe exhaust emission reduction, and reduced vehicular fuel consumption (and therefore the need for crude oil feedstocks). Burdens would fall both on the water hauling service companies and on the water disposal companies. These burdens would include agreements to cooperate (which would include the setting of prices), the purchase of compatible radio equipment, and the implementation of a central dispatch facility. There would be no tradeoffs associated with this strategy. Assistance is needed from the Cumulative Effects work group to estimate the net air quality gain from optimizing produced water hauling routes.

II. Description of how to implement

This mitigation option could be implemented on a mandatory basis. In order to set fair prices on water hauling and disposal (like taxi cabs), it would be necessary to involve other agencies and potentially special legislation.

The most appropriate agency to implement would be the states' regulatory entity for the oil and gas industry. It would be necessary to first understand the relative benefit of reducing emissions from lease road traffic due to optimization (Cumulative Effects Work Group task).

III. Feasibility of the option

Technical – The technology exists today to implement this mitigation option.

Environmental – A study would need to be made to determine the relative benefit of reducing emissions from lease road traffic due to optimization (Cumulative Effects Work Group task).

Economic – Implementation of this technology should be economically feasible.

IV. Background data and assumptions used

No input information was available in the time frame desired to make any calculations / determinations. Hence the high-level and qualitative analysis. This could be a Cumulative Effects Work Group task.

V. Any uncertainty associated with the option (Low, Medium, High)

Low. Assistance from the Cumulative Effects work group would be needed to understand the relative environmental benefit of optimized truck traffic. Once that is understood, an analysis could be made to reduce the economic and regulatory uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups (please describe the issue and which groups

It is believed that this issue will not cross-over to any other source work group.

Mitigation Option: Use Alternative Fuels and Maximize Fuel Efficiency to Control Combustion Engine Emissions

I. Description of the mitigation option

This option involves the implementation of alternative fuels, ultra low sulfur diesel (15 ppm) and improved fuel efficiency for heavy-duty trucks (Class 7 – GVW 26,001 to 33,001). The air quality benefits include potential reduction of sulfur, greenhouse gases and aromatic compounds throughout the region. Other environmental impacts include a reduction in petroleum consumption and conservation of natural resources.

Economic burdens include the cost of the new alternative fuel/fuel efficient vehicle and cost and availability of the fuel.

There would not be adverse environmental justice issues associated with the implementation of alternative fuels. There is potential for air quality improvements from travels through socio-economically disadvantaged communities with improved fuel efficiency.

Low sulfur diesel can continue to be used in 2006 and older highway vehicles until 2010. Any new 2007 model year highway diesel vehicle will be required to use ultra low sulfur diesel (ULSD). ULSD must be available at retail by October 15, 2006. Terminals should be turned over to ULSD by the end of July. They could consider using ULSD for the non-road equipment too and get even more reductions in PM as well.

II. Description of how to implement

A. Mandatory or voluntary: There may be some mandatory upgrades for new heavy-duty trucks purchased after a set date. The immediate move to alternative fuel vehicles should be a voluntary program and could be incorporated into the San Juan Vistas or similar program. Likewise the states could adopt tax advantaged strategies under a voluntary program to encourage the adoption of alternative fuels.
B. Indicate the most appropriate agency(ies) to implement**:** NM Dept. of Transportation, Colorado Dept. of Transportation, Federal Highway Administration.

III. Feasibility of the option

A. Technical: Oil and gas industry have developed a diesel fuel made from natural gas through the Fischer-Tropsch (F-T) process, there are other synthetic liquid fuels and major heavy-duty diesel engine companies are working on engines with reduced NOx and particulate emissions.
B. Environmental: The environmental benefits would primarily be associated with reduced consumption of petroleum resources.
C. Economic: The market will have to drive economically viable alternatives. According to referenced studies, Class 7 Heavy Duty Vehicles use a smaller percentage of fuel than Class 8 trucks (long-haul tractor- trailers), Class 2b vehicles (light trucks) or Class 6 vehicles (delivery vans).

IV. Background data and assumptions used

1. Life Cycle Analysis for Heavy Vehicles by Argonne National Laboratory Transportation Technology R&D Center.
2. Heavy Vehicle Technology and Fuels September 2004 – Argonne National Laboratories Transportation Technology R&D Center.
3. Green Machines facts and figures associated with fuel type, consumption rates, and emissions factors (reference)

V. Any uncertainty associated with the option High.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to other source groups None at this time.

Mitigation Option: Utilize Exhaust Emission Control Devices for Combustion Engine Emission Controls

I. Description of the mitigation option

This option involves the implementation of exhaust emission control devices for heavy-duty trucks (Class 7 – GVW 26,001 to 33,001) such as diesel oxidation catalysts (DOC), diesel particulate filters and/or traps. The air quality benefits include potential reduction of particulate matter and NOx throughout the region.

Economic burdens include the cost associated with the installation and maintenance of the exhaust emission control devices.

There would not be environmental justice issues associated with the implementation of emission controls.

II. Description of how to implement

A. Mandatory or voluntary: There may be some mandatory upgrades for new heavy-duty trucks purchased after a set date. The immediate move to emission controls should be a voluntary program and could be incorporated into the San Juan Vistas or similar program.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option

A. Technical: Technology exists.
B. Environmental: The environmental benefits would primarily be associated with reduced particulates and NOx.

Most devices are also effective at reducing VOCs, and therefore air toxics and ozone. In fact, the most common, inexpensive, and most demonstrated technologies are oxidation catalysts, which are more effective at removing VOCs than PM and NOx. After treatment technologies for reducing NOx (especially on mobile engines) are still evolving, and so strategies for reducing NOx typically rely on fuel emulsifiers, engine modifications/repair, and engine replacements.

C. Economic: The market will have to drive economically viable alternatives. According to referenced studies, Class 7 Heavy Duty Vehicles use a smaller percentage of fuel than Class 8 trucks (long-haul tractor- trailers), Class 2b vehicles (light trucks) or Class 6 vehicles (delivery vans).

IV. Background data and assumptions used

1. Life Cycle Analysis for Heavy Vehicles by Argonne National Laboratory Transportation Technology R&D Center.
2. Heavy Vehicle Technology and Fuels September 2004 – Argonne National Laboratories Transportation Technology R&D Center.
3. US EPA Clean Diesel and Trucks Rule
4. Green Machines facts and figures associated with fuel type, consumption rates, and emissions factors (reference)

V. Any uncertainty associated with the option (Low, Medium, High) High

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to other source groups

Mitigation Option: Exhaust Engine Testing for Combustion Engine Emission Controls

I. Description of the mitigation option
This option involves the implementation of an inspection and maintenance program to determine if emission controls and engines are functioning properly resulting in reduced emissions. Compliance with the standards set in the 2000 Heavy Duty Highway Clean Diesel Trucks and Buses Rule can be tested with an inspections and maintenance testing program. Environmental benefits include potential reduction of sulfur, NOx and particulates throughout the region.

Economic burdens include the cost of the inspection program, equipment, inspectors, and mobile or stationary inspection facilities.

There would not be environmental justice issues associated with the implementation of exhaust engine testing.

II. Description of how to implement
A. Mandatory or voluntary: Mandatory participation would be required.
B. Indicate the most appropriate agency(ies) to implement**:** NM Dept. of Transportation, Colorado Dept. of Transportation, Federal Highway Administration.

III. Feasibility of the option
A. Technical: Numerous states currently use exhaust emission testing. Details on mobile inspection programs are widely available.
B. Environmental: The environmental benefits would primarily be associated with reduced sulfur, particulates and compliance with Clean Diesel Trucks Rule.

Most devices are also effective at reducing VOCs, and therefore air toxics and ozone. In fact, the most common, inexpensive, and most demonstrated technologies are oxidation catalysts, which are more effective at removing VOCs than PM and NOx. After treatment technologies for reducing NOx (especially on mobile engines) are still evolving, and so strategies for reducing NOx typically rely on fuel emulsifiers, engine modifications/repair, and engine replacements.

C. Economic: The market will have to drive economically viable alternatives. According to referenced studies, Class 7 Heavy Duty Vehicles use a smaller percentage of fuel than Class 8 trucks (long-haul tractor- trailers), Class 2b vehicles (light trucks) or Class 6 vehicles (delivery vans).

IV. Background data and assumptions used
1. Life Cycle Analysis for Heavy Vehicles by Argonne National Laboratory Transportation Technology R&D Center.
2. Heavy Vehicle Technology and Fuels September 2004 – Argonne National Laboratories Transportation Technology R&D Center.
3. US EPA Clean Diesel and Trucks Rule
4. Green Machines facts and figures associated with fuel type, consumption rates, and emissions factors (reference)

V. Any uncertainty associated with the option (Low, Medium, High) Medium

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to other source groups None at this time.

Mitigation Option: Reduce Trucking Traffic in the Four Corners Region

I. Description of the mitigation option
This option involves implementing various measures to reduce the mileage required to truck fluids or equipment for oil and gas exploration, production, or treating operations. The air quality benefits include increased operating efficiency by 10% which will equate to 10% reduced fuel usage, which results in a net reduction of emissions of NOx by [ ] tons per day, SOx by [ ] tons per day, a reduction in greenhouse gas emissions of [ ] and PM2.5 emissions by [ ] tons per day. Other environmental impacts include reduced dust and noise from the trucks and roads at nearby residences, and reduced unintentional killing of wildlife and livestock that may be killed truck traffic.

Economic burdens include the cost of centralized facilities and systems designed to maximize routing efficiency, which may be partially offset by the benefits to human health of improved air quality and reduction of highway traffic (and traffic accidents) in the region.

There should not be any environmental justice issues associated with the placement of the centralized tank batteries (including produced water tanks, condensate tanks and/or crude oil tanks) in socio-economically disadvantaged communities.
Differing opinion: There are potential health hazards associated with crude oil and condensate tank emissions. Concentrating these facilities in socio-economically disadvantaged communities is an example of environmental injustice.

II. Description of how to implement
A. Mandatory or voluntary: The implementation of measures to maximize routing efficiency and reduce truck trips are envisioned as a "voluntary" measures to enhance operating efficiency and could be easily incorporated as a BMP in voluntary programs such as the NMED San Juan VISTAs program. Furthermore, the state could adopt tax advantages strategies to allow companies to reduce their taxes by showing reduced emissions from adopting improved routing or operating efficiency. There are currently no mechanisms or rules to require mandatory efficiency standards and this seems implausible as a mandatory approach.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option
A. Technical: The use of centralized facilities is technically feasible as is software to maximize routing efficiency.
B. Environmental: The environmental benefits of reduced vehicle mileage are well documented.
C. Economic: These options need to be explored by individual companies as to their economic viability.

IV. Background data and assumptions used
1. Water hauling is necessary in NM due to the lack of pipeline infrastructure to pipe the fluids directly to SWD facilities; Colorado has a greater use of pipelines.
2. Trucking companies will not react adversely to reduced economics from less vehicle miles.

V. Any uncertainty associated with the option Medium.

VI. Level of agreement within the work group for this mitigation option General agreement among drafting team members that this is viable and probable.

VII. Cross-over issues to other source groups None at this time.
Differing opinion: Some indication by the Cumulative Effects group of the potential emissions reduced would be helpful.

ENGINES: RIG ENGINES

Mitigation Option: Diesel Fuel Emulsions

I. Description of the mitigation option

Diesel Fuel Emulsions:

- This option, which is an EPA verified retrofit technology, reduces peak engine combustion temperatures and increases fuel atomization and combustion efficiency.
  Differing opinion: The EPA study only looked at the "summer" blend of diesel emulsion. There is no data available to evaluate neither the compatibility with winter temperatures nor the emissions effects at winter temperatures.
- It is accomplished by using surfactant additives to encapsulate water droplets in diesel fuel to form a stable mixture while ensuring that the water does not contact metal engine parts.
- Air quality benefit:

	% Reductions[2, 3]			
Non-Road [1]	PM	CO	NOx	HC
0-100 hp	23	(35)	19	(99)
100-175 hp	17	13	17	(80)
175-300 hp	17	13	19	(73)
>300 hp	17	13	20	(30)

1. Estimate using 2D fuel, <500 ppm sulfur.
2. (##) indicates an increase
3. Based on verification results supplied to EPA by Lubrizol for PuriNOx emulsion.
   Differing Opinion: CARB's verified NOx reductions were lower (14%) than EPA's as shown in the above table. This suggests a need for a more extensive review prior to finalizing this option.

- Can be used in conjunction with a diesel oxidation catalyst to reduce HC and CO emissions and further reduce PM.
- Emission control performance is better in lower load/lower speed applications.
- Emulsions have about a 12-month shelf life.
- Typically experience a 20% power loss when operating at maximum engine horsepower. The power loss is potentially a fatal flaw in this method. Most rig engines are sized for the maximum load expected and would have to be refitted with larger engines to handle the equivalent maximum loads.
- Will expect a 15% increase in fuel consumption for equipment operating on fuel with emulsion additive. [This will increase SO2 emissions by 15%. The mass will depend on the sulfur content of the fuel. It will also increase fuel delivery truck emissions by 15% along with road dust emissions due to fuel hauling by 15%.
- Not compatible with optical or conductivity-type fuel sensors, water absorbing water separators, water absorbing fuel filters, or centrifugal style water separators.
- Engine must be run for at least 15 minutes every 30 days.
- Incremental cost increase of $0.10 to 0.20 per gallon.
  Differing opinion: The increased fuel cost on top of the 15% increase in fuel consumption makes this a very expensive option. For a "typical" 16 day Wyoming Green River Basin well using 19,816 gallons of diesel, the 15% fuel penalty would represent about $6,000 additional fuel cost and the average premium ($0.15/gal) would represent about $3,400 additional fuel cost for a NOx benefit of about 1 ton reduction – or a cost of about $9,400 per ton of NOx. This seems very excessive and does not include the additional costs required for separate mixing and storage of the emulsified fuel. There may also be incremental labor costs for the technicians to operate the system. The incremental cost per gallon needs to be updated and verified – the cost quoted dates

to the original study date. Installation of oxidation catalyst to control hydrocarbon and CO emissions would add additional cost and complexity to an already cost prohibitive option.

- Requires mixing of fuel with emulsion and a storage unit for the emulsion and or mixed fuel. Some burden on technicians to properly operate and mix some simple equipment.

II. Description of how to implement

This voluntary option would be relatively simple using EPA verified retrofit technology. Some analysis is required to ensure that duty cycle (how long will engine and fuel be idle) and ambient temperatures are compatible with the emulsion product. Storage tanks and some training and capable technicians will be required to put into operation the relatively simple mixing equipment.

Differing opinion: The power penalties, incremental mixing and storage equipment, and increased technical knowledge necessary make this option do-able, but not necessarily simple.

III. Feasibility of the option

A. Technical: Technically this is one of the simplest options available.

B. Environmental: Fuel emulsion has potential for increased carbon monoxide and hydrocarbon emissions, but this downside could be overcome by use of a diesel oxidation catalyst. One additional issue with the emulsion option is that if the emulsion is no longer purchased or used the emission benefit goes away, in comparison to permanent exhaust treatments or improved engines or hardware.

C. Economic: There would be capital cost for emulsion and/or mixture storage and ongoing incremental cost per gallon.

Differing opinion: This option should be characterized as an expensive one. Using a “typical” 16 day Wyoming Green River Basin well using 19,816 gallons of diesel the 15% fuel penalty would represent about $6,000 additional fuel cost and the average premium ($0.15/gal) would represent about $3,400 additional fuel cost for a NOx benefit of about 1 ton reduction – or a cost of about $9,400 per ton of NOx. This seems very excessive and does not include the additional costs required for separate mixing and storage of the emulsified fuel. There may also be incremental labor costs for the technicians to operate the system.

IV. Background data and assumptions used

As an EPA verified retrofit, the data and assumptions associated with this option have been well evaluated and considered.

Differing opinion: The evaluation of applicability in cold weather needs to be done.

V. Any uncertainty associated with the option (Low, Medium, High)

Low uncertainty as this is a verified, simple retrofit.

Differing opinion: Given the high apparent cost, no evaluation in cold weather, different reduction percentages from separate evaluations, and complexity, this option should not be considered low uncertainty.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups (please describe the issue and which groups

None at this time.

Mitigation Option: Natural Gas Fired Rig Engines

I. Description of the mitigation option

Install natural gas fired engines on rigs in the Four Corners region.

Benefits

- Air Quality - Natural gas engines emit less and NOx,
  - ~ 85% reduction of NOx vs. Tier I engines.
    Differing opinion: Given the variable load (and often low load) on drilling rig engines, the "best" lean burn natural gas engine performance expected would be in the range of 2 to 3 grams per hp-hr. This represents about a 65-75% reduction from Tier 1 diesel engines. Please note this would require lean burn engines.
  - ~ 91% reduction of NOx vs. Tier 0 engines
    Differing opinion: Given the variable load (and often low load) on drilling rig engines, the "best" lean burn natural gas engine performance expected would be in the range of 2 to 3 grams per hp-hr. This represents about a 65-75% reduction from Tier 1 diesel engines. Please note this would require lean burn engines.
  - Natural gas engines emit less particulate matter (PM) on a larger percent reduction basis than the NOx percentages above.
- Cost Savings?
  - If the natural gas fuel source is in close proximity and little piping is required, its use may be less expensive than diesel, which is currently hauled to the rig.
    Differing opinion: On a purely fuel basis this may be true without considering the retrofit costs.
  - Savings in fuel cost is dependent on product price.

Tradeoffs

- CO levels increase with natural gas usage, ~ 175%

Burdens

- Fuel Source
  - A natural gas fuel source sufficient to power the rig engines may not be readily available at every site.
  - Installation of piping to transport the natural gas may increase safety risks for workers and may potentially require right-of-way that can significantly delay projects (months to years).
  - Natural gas usage may require mineral owner approval, metering and appropriate allocation potentially resulting in permitting delays and increased administrative support
  - Fuel supply needs careful tuning and monitoring due to varying amounts of produced water that may be present. Also impacted by variations in fuel quality in the different areas and formations of a field. Could also require the installation of a dehydrator if gas is wet and the field uses a central dehydration system.
  - Engine size must increase to achieve an equivalent horsepower yield. For example a Cat 3512 diesel would have to be replaced with a Cat 3516 natural gas engine to get approximately the same horsepower.
- Rig Operations
  - Slower power response and less torque requires learning curve on rigs
  - Not well suited for Mechanical Rigs – Electric rigs are preferred. Information from natural gas fueled engine rigs in Wyoming indicates that a "load bank" is required due to the slower response of the engines to power demand.
- Cost
  - Initial Capital Investment – up to 1.2 MM$ / Rig for retrofit

- If the natural gas fuel source is distant or not available for other reasons, the associated piping or use of LNG may be significantly more expensive than diesel.
  Differing opinion: LNG is not a viable fuel – it is not readily available, requires refrigerated storage, and requires "re-gas" equipment. Conversion to natural gas fuels essentially limits the utility of a particular rig to just those instances where gas is available.

- Availability
  - Engine availability is limited

II. Description of how to implement
A. Mandatory or voluntary: Voluntary
B. Indicate the most appropriate agency(ies) to implement**:** None

III. Feasibility of the option
A. Technical: A natural gas fired rig engine is currently being utilized in Wyoming in the Jonah Field indicating that the technology works. However, the Jonah field is significantly different from the San Juan Basin enabling easier access to natural gas as a fuel source. The wells in the Jonah Field are more closely spaced (10 acre vs. 80 acre) and deeper allowing for the directional drilling of several wells from a single well pad and close proximity to currently producing wells.

B. Environmental: Installation of natural gas fired engines on new rigs will significantly reduce NOx emissions for those rigs, but may result in other environmental impacts, including an increase in CO emissions and potential land disturbance related to installation of natural gas pipelines to deliver the fuel.

C. Economic: In some cases where a natural gas fuel source is nearby, fuel costs may be lower than for diesel. In other cases, where access to natural gas can only be obtained by installing a large amount of pipe that potentially requires a right-of-way or by using LNG, the costs may be significantly higher. Conversion to natural gas fired engines essentially limits the use of a rig to only those instances where gas is available. The conversion/retrofit costs are high.
Differing opinion: See LNG comments above.

IV. Background data and assumptions used
Utilized Encana data obtained from Ensign 88 – Natural Gas Rig (2 3516 LE Natural Gas Engines on 1200 KW Generators)

V. Any uncertainty associated with the option (Low, Medium, High) High

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to other source groups

Mitigation Option: Selective Catalytic Reduction (SCR)

I. Description of the mitigation option

Selective Catalytic Reduction (SCR)

Description

Selective catalytic reduction (SCR) is the process where a reductant (typically ammonia or urea) is added to the flue gas stream and is absorbed onto the catalyst (typically vanadium or zeolite) enabling the chemical reduction of NOx to molecular nitrogen and water. Diesel engines typically have unconsumed oxygen in the exhaust, which inhibits removal of oxygen from the NOx molecules. To remove the unconsumed oxygen, the catalyst decomposes the reductant causing the release of hydrogen, which reacts with the oxygen. This creates local oxygen depletion near the catalyst allowing the hydrogen to also react with the NOx molecules to form nitrogen and water.

Benefits

- NOx emission reductions of 80-90% are achieved. NOx emission reductions of up to 80-90% are achievable.
- Potential to reduce hydrocarbon, hazardous air pollutant, and condensable particulate matter (PM) emissions based on emissions tests.
- Technology is available currently.
- SCR systems designed primarily to reduce NOx have been designed with PM filtering capabilities.

Tradeoffs

- Ammonia Slip

The SCR process requires precise control of the ammonia injection rate. An insufficient injection may result in unacceptably low NO_x conversions. An injection rate that is too high results in release of undesirable ammonia to the atmosphere. These ammonia emissions from SCR systems are known as *ammonia slip*. Ammonia slip will also occur when exhaust gas temperatures are too cold for the SCR Reaction to occur. Ammonia slip can potentially be controlled by an oxidation catalyst installed downstream of the SCR catalyst. Diesel oxidation catalysts are often used downstream of NOx catalysts for ammonia reduction.

Burdens

- Minimum and maximum temperature ranges limit the effectiveness of the SCR system.
  - The SCR system requires a minimum exhaust temperature of 572°F (300°C) and maximum of 986°F (530°C) for NOx reduction to occur (optimal range).
- The SCR systems had faults and system errors that can shut the urea injection system off.
  - ENSR testing had problems with the NO2 measuring cells that had multiple high and low pressure and measurement alarms.
- The SCR system needs operator attention.
  - The SCR system needs to be tuned to the engine operating cycle. This requires running the engine through a simulation of the operating cycle of the machine it will be fitted to (engine mapping).
  - Typically SCR catalysts require frequent cleaning even with pure reductants, as the reductant can cake the inlet surface of the catalyst while the exhaust gas stream temperature is too low for the SCR reaction to take place.
- Potential for ammonia slip
- Cost (Retrofit)
  - Capital Expenditure Costs - ~$130,000 / new SCR unit

– Operating Expenditure Costs - ~$143,000 / year / unit 1
– Costs extrapolated out over a 10-year period would equate to **$1.56 MM / engine equipped.**
– Need for reductant (NH_3) adds to the engine operating cost (in the range of 4% of the equipment operating fuel cost).

Non-Selective Catalytic Reduction (NSCR)
NSCR is not applicable to diesel engines.

II. Description of how to implement
A. Mandatory or voluntary: The workgroup believes that more information is required on the contribution of rig emissions to the total NOx emissions and the potential ammonia emissions impact to visibility prior to determining whether this mitigation should be mandatory or voluntary.
.
B. Indicate the most appropriate agency(ies) to implement: The states.

III. Feasibility of the option
A. Technical: The technology is available and effective in reducing NOx emissions.
B. Environmental: Proven reduction of NOx emissions, however the potential increase of ammonia emissions and subsequent impact to visibility is not well understood.
C. Economic: Capital costs associated with a new engine with SCR or installation of retrofit SCR are feasible. Additional costs associated with operation and maintenance may not be feasible for some rig operators.

IV. Background data and assumptions used
Utilized information from ENSR Presentation - *Technology Demonstration – Selective Catalytic Reduction (SCR) and Bi-Fuels Implementation on Drill Rig Engines*

V. Any uncertainty associated with the option (Low, Medium, High)
Medium – It is clear that SCR is effective in reducing NOx emissions, however an understanding of the potential increase of ammonia emissions and the resulting impacts to visibility need to be understood.

VI. Level of agreement within the work group for this mitigation option
The workgroup agrees that this is a potential mitigation option, but requires more information regarding ammonia emissions and the overall contribution of NOx emissions from rigs.
EPA has SCR listed as a Potential Retrofit Technology for diesel engines.

VII. Cross-over issues to the other source groups (please describe the issue and which groups
Cumulative Effects Workgroup – The Rig Engines Drafting Workgroup requires information on the estimated contribution of NOx emissions from rig engines and on the impact of ammonia emissions on visibility (what are local levels currently, how will increasing ammonia emissions impact visibility?).

Mitigation Option: Selective Non-Catalytic Reduction (SNCR)

I. Description of the mitigation option

Selective Non-Catalytic Reduction (SNCR) is a post-combustion treatment in which ammonia is injected into the flue gas stream. The ammonia reacts with the NOx compounds, forming nitrogen and water. In order for this technique to be effective, the ammonia must be injected at a proper temperature range within the stack and must be in the proper ratio to the amount of NOx present. The reduction reaction at temperatures ranging from 925 – 1125ºC does not require catalysis and can achieve 40% NOx control. More modest NOx reductions are reported in the 725 - 925ºC range.

Differing Opinion: These are very high temperatures and much greater than the temperatures in diesel engine exhaust. For example, the data sheet for a Cat 3512 diesel rig engine shows a “highest” exhaust temperature of ~792 degrees F. Based on the degradation in performance reported in the 725 – 925 degrees C it probably would have very little effect at the exhaust temperatures from rig engines. This technology is really tested for very high temperature boilers only – not engines.

Benefits

- NOx emission reductions of ~40% (range 20-55%) are achieved in optimal temperature range.
- Avoids the expense of a catalyst.
- Technology is available currently.

Tradeoffs

- Ammonia Slip – 10 ppm ammonia slip is considered reasonable for SNCR. 10 ppm represents about 16 tons/yr of ammonia from a single fully loaded Cat 3512 engine. Given that most rigs have two or more engines it is not much of a stretch to have very significant ammonia emissions with the number of rigs running in the basin. This amount of ammonia may enhance secondary particulate formation with consequent effects on PM 2.5 (health based) and visibility (perception based).

Burdens

SNCR tends to have high operating costs - cost is estimated at $600 - $1300/ton

Mobile source engines (rig engines) are usually not a good candidate for SNCR because typical operating temperatures are below the levels needed for effective operation.

II. Description of how to implement

A. Mandatory or voluntary: The workgroup believes that more information is required on the contribution of rig emissions to the total NOx emissions and the potential ammonia emissions impact to visibility prior to determining whether this mitigation should be mandatory or voluntary.

B. Indicate the most appropriate agency(ies) to implement: Colorado Department of Public Health and Environment (CDPHE), New Mexico Environment Department (NMED).

III. Feasibility of the option

A. Technical: The technology is available and effective in reducing NOx emissions.

Differing Opinion: There is no available data indicating applicability to engines or much lower temp operation. This option should be considered as non-feasible.

B. Environmental: Proven reduction of NOx emissions, however the potential increase of ammonia emissions and subsequent impact to visibility is not well understood.

C. Economic: Costs associated with operation and maintenance may not be feasible for some rig operators.

IV. Background data and assumptions used
State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines – State of New Jersey, Department of Environmental Protection, Division of Air Quality

V. Any uncertainty associated with the option
Medium – SNCR is effective in reducing NOx emissions, however an understanding of the potential increase of ammonia emissions and the resulting impacts to visibility need to be understood.

VI. Level of agreement within the work group for this mitigation option
The workgroup agrees that this is a potential mitigation option, but requires more information regarding ammonia emissions and the overall contribution of NOx emissions from rigs.

VII. Cross-over issues to the other source groups
Cumulative Effects Workgroup – The Rig Engines Drafting Workgroup requires information on the estimated contribution of NOx emissions from rig engines and on the impact of ammonia emissions on visibility (what are local levels currently, how will increasing ammonia emissions impact visibility?).

Mitigation Option: Implementation of EPA's Non Road Diesel Engine Rule – Tier 2 through Tier 4 Standards

I. Description of the mitigation option

In short this option would require the use of engines that at minimum meet EPA Tier 2 non-road on a fleet average basis and that all newly installed engines would meet the most current EPA standard (Tier 2 through 4).

In 1998, EPA adopted more stringent emission standards ("Tier 2" and "Tier 3") for NOx, hydrocarbons (HC), and PM from new nonroad diesel engines. This program includes the first set of standards for nonroad diesel engines less than 50 hp (phasing in between 1999 and 2000), phases in more stringent "Tier 2" emission standards from 2001 to 2006 for all engine sizes, and adds more stringent "Tier 3" standards for engines between 50 hp and 750 hp from 2006 to 2008.

In June 2004, EPA adopted additional nonroad diesel engines emission standards. These standards are known as "Tier 4." This comprehensive national program regulates nonroad diesel engines and diesel fuel as a system. New engine standards will begin to take effect in the 2008 model year, phasing in over a number of years.

The pertinent regulations are as follows:

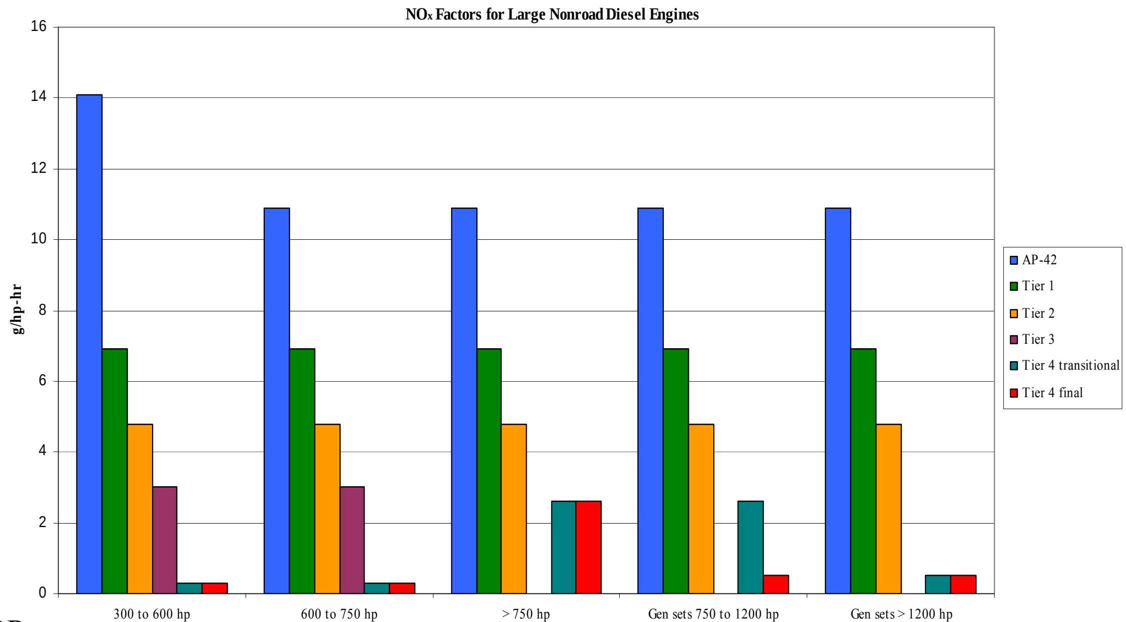
Clean Air Nonroad Diesel - Tier 4 Final Rule: Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel, 69 FR 38957, June 29, 2004

Tier 2 and Tier 3 Emission Standards - Final Rule: Control of Emissions of Air Pollution from Nonroad Diesel Engines, 63 FR 56967, October 23, 1998

Drill rig engines would be considered "non-road engines" because of the definition of non-road engine in 40 CFR 1068.30 (1)(iii) and (2)(iii) – assuming the rig moves more often than every 12 months.

These non-road diesel standards do not apply to existing non-road equipment. Only equipment built after the start date for an engine category (1999- 2006, depending on the category) is affected by the rule.

The Tier 2, 3, and 4 Emission Standards for large (> 300 hp) are as follows: [AP42 (Tier 0) and Tier 1 shown for comparison purposes]



OR

	300 to 600 hp	600 to 750 hp	> 750 hp (Excluding Gen Sets)	Gen sets 750 to 1200 hp	Gen sets > 1200 hp
AP-42	14.1*	10.9**	10.9**	10.9**	10.9**
Tier 1	6.9	6.9	6.9	6.9	6.9
Tier 2	4.8	4.8	4.8	4.8	4.8
Tier 3	3	3			
Tier 4 transitional	0.3	0.3	2.6	2.6	0.5
Tier 4 final	0.3	0.3	2.6	0.5	0.5

*AP-42 Table 3.3-1 **AP-42 Table 3.4-1 shading -- NMHC + NOx

The Tier 2, 3, and 4 Emission Standards for large (> 300 hp) are as follows: [AP42 (Tier 0) and Tier 1 shown for comparison purposes]

Effective Dates of Tier Standards, Nonroad Diesel Engines, by Horsepower

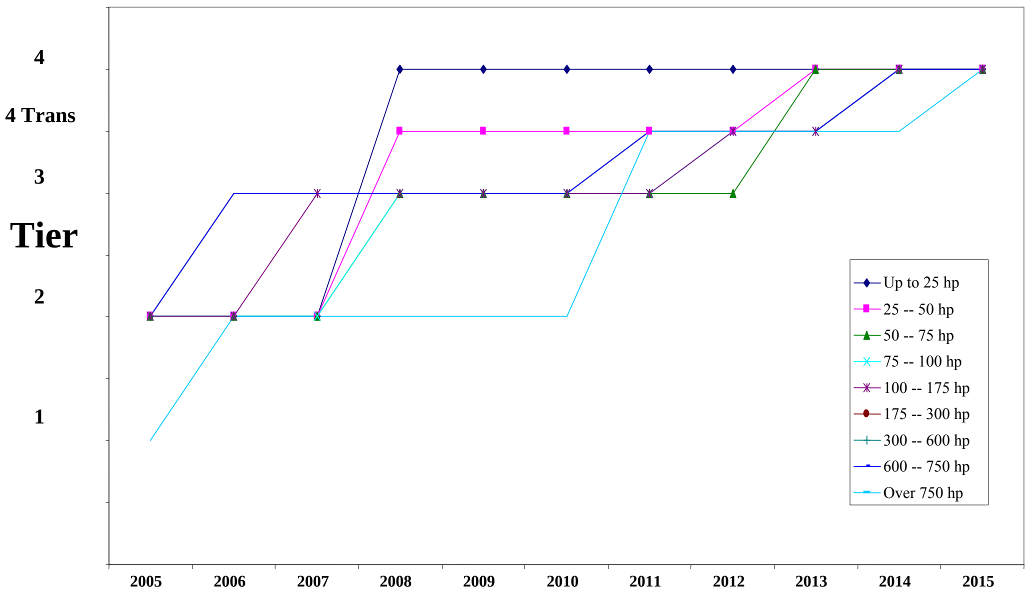


Table 1. Nonroad CI Engine Emission Standards[a]

Engine Power (hp)	Model Years	Regulation	Emission Standards (g/hp-hr)					NONROAD Tech Types
			HC [b]	$NMHC+NO_x$	CO	NO_x	PM	
<11	2000-2004	Tier 1		7.8	6.0		0.75	T1
	2005-2007	Tier 2		5.6	6.0		0.60	T2
	2008+	Tier 4					0.30	T4A, T4B [e]
≥11 to <25	2000-2004	Tier 1		7.1	4.9		0.60	T1
	2005-2007	Tier 2		5.6	4.9		0.60	T2
	2008+	Tier 4					0.30	T4A, T4B [e]
≥25 to <50	1999-2003	Tier 1		7.1	4.1		0.60	T1
	2004-2007	Tier 2		5.6	4.1		0.45	T2
	2008-2012	Tier 4 transitional					0.22	T4A
	2013+	Tier 4 final		3.5			0.02	T4
50 to <75	1998-2003	Tier 1				6.9		T1
	2004-2007	Tier 2		5.6	3.7		0.30	T2
	2008-2012	Tier 3 [c]		3.5	3.7			T3
	2008-2012	Tier 4 transitional [c]					0.22	T4A
	2013+	Tier 4 final		3.5			0.02	T4
≥75 to <100	1998-2003	Tier 1				6.9		T1
	2004-2007	Tier 2		5.6	3.7		0.30	T2
	2008-2011	Tier 3		3.5	3.7			T3B
	2012-2013	Tier 4 transitional	0.14 (50%) [d]			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N
≥100 to <175	1997-2002	Tier 1				6.9		T1
	2003-2006	Tier 2		4.9	3.7		0.22	T2
	2007-2011	Tier 3		3.0	3.7			T3
	2012-2013	Tier 4 transitional	0.14 (50%)			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N
≥175 to <300	1996-2002	Tier 1	1.0		8.5	6.9	0.4	T1
	2003-2005	Tier 2		4.9	2.6		0.15	T2
	2006-2010	Tier 3		3.0	2.6			T3
	2011-2013	Tier 4 transitional	0.14 (50%)			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N

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Engine Power (hp)	Model Years	Regulation	Emission Standards (g/hp-hr)					NONROAD Tech Types
			HC [b]	NMHC+NO_x	CO	NO_x	PM	
≥300 to <600	1996-2000	Tier 1	1.0		8.5	6.9	0.4	T1
	2001-2005	Tier 2		4.8	2.6		0.15	T2
	2006-2010	Tier 3		3.0	2.6			T3
	2011-2013	Tier 4 transitional	0.14 (50%)			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N
≥600 to ≤750	1996-2001	Tier 1	1.0		8.5	6.9	0.4	T1
	2002-2005	Tier 2		4.8	2.6		0.15	T2
	2006-2010	Tier 3		3.0	2.6			T3
	2011-2013	Tier 4 transitional	0.14 (50%)			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N
>750 except generator sets	2000-2005	Tier 1	1.0		8.5	6.9	0.4	T1
	2006-2010	Tier 2		4.8	2.6		0.15	T2
	2011-2014	Tier 4 transitional	0.30			2.6	0.075	T4
	2015+	Tier 4 final	0.14			2.6	0.03	T4N
Generator sets >750 to ≤1200	2000-2005	Tier 1	1.0		8.5	6.9	0.4	T1
	2006-2010	Tier 2		4.8	2.6		0.15	T2
	2011-2014	Tier 4 transitional	0.30			2.6	0.075	T4
	2015+	Tier 4 final	0.14			0.5	0.02	T4N
Generator sets >1200	2000-2005	Tier 1	1.0		8.5	6.9	0.4	T1
	2006-2010	Tier 2		4.8	2.6		0.15	T2
	2011-2014	Tier 4 transitional	0.30			0.5	0.075	T4
	2015+	Tier 4 final	0.14			0.5	0.02	T4N

[a] These standards do not apply to recreational marine diesel engines over 50 hp. Standards for this category are provided in Table 7.
[b] Tier 4 standards are in the form of NMHC.
[c] For 50 to <75 hp engines, a Tier 3 NO_x standard of 3.5 g/hp-hr was promulgated, beginning in 2008. The Tier 4 transitional standard also begins in 2008; it leaves the Tier 3 NO_x standard unchanged and adds a 0.22 g/hp-hr PM standard.
[d] Percentages are model year sales fractions required to comply with the indicated NO_x and NMHC standards, for model years where less than 100 percent is required.
[e] The T4A tech type is used in 2008-2012. The T4B tech type is used in 2013+.

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II. Description of how to implement

A. Mandatory or voluntary
Compliance with these regulations is required for new and rebuilt engines after the specified deadlines. The Four Corners Task Force is studying the potential for quicker implementation of the standards based on a voluntary agreement to either retrofit existing engines to meet the Tier 2 through Tier 4 standards or use of new Tier 2 through Tier 4 compliant engines.

B. Indicate the most appropriate agency(ies) to implement

EPA implements the non-road engine regulations nationally by certifying engine manufacture test results, but state regulatory agencies would be involved in any agreements for accelerated implementation of the standards in the Four Corners area.

III. Feasibility of the option

A. Technical
Some engine industry authorities indicate anecdotally that the supply of the new, cleaner engines may fall short of the demand for them particularly in the oil and gas industry.

In 1998, EPA adopted more stringent emissions standards for nonroad diesel engines. In that rulemaking, EPA indicated that in 2001 it would review the upcoming Tier 3 portion of those standards (and the Tier 2 emission standards for engines under 50 horsepower) to assess whether or not the new standards were technologically feasible. EPA drafted a technical paper with a preliminary assessment of the technological feasibility of the Tier 2 and Tier 3 emission standards - http://www.epa.gov/nonroad-diesel/r01052.pdf

In this assessment EPA determined that the standards were feasible with technologies such as the following:

Charge Air Cooling - Air-to-air or air-to-water cooling at intake manifold reduces peak temperature of combustion. (Controls NOx)

Fuel Injection Rate Shaping & Multiple Injections - Controls fuel injection rate, limiting rate of increase in temperature & pressure. (Controls NOx)

Ignition Timing Retard - Delays start of combustion, matching heat release with power stroke. (Controls NOx)

Exhaust Gas Recirculation - (1) Reduces peak cylinder temperature, (2) dilutes O_2 with inert gases, (3) dissociates CO_2 & H_2O endothermic. (Controls NOx)

B. Environmental
The Tier 2 and 3 standards will reduce emissions from a typical nonroad diesel engine by up to two-thirds from the levels of previous standards. By meeting these standards, manufacturers of new nonroad engines and equipment will achieve large reductions in the emissions (especially NOx and PM) that cause air pollution problems in many parts of the country. EPA estimates that by 2010, NOx emissions nationally will be reduced by about a million tons per year because of the Tier 2 and 3 standards.

When the full inventory of older nonroad engines are replaced by Tier 4 engines, annual emission reductions nationally are estimated at 738,000 tons of NOx and 129,000 tons of PM. By 2030, 12,000 premature deaths would be prevented annually due to the implementation of the proposed standards. EPA estimates that NOx emissions from these engines will be reduced by 62 percent in 2030.

C. Economic
EPA estimates the costs of meeting the Tier 2 and 3 emission standards are expected to add well under 1 percent to the purchase price of typical new non-road diesel equipment, although for some equipment the standards may cause price increases on the order of two or three percent. The program is expected to cost about $600 per ton of NOx reduced, which compares very favorably with other emission control strategies.

The estimated costs for added emission controls for the vast majority of equipment was estimated at 1-3% as a fraction of total equipment price. For example, for a 175 hp bulldozer that costs approximately $230,000 it would cost up to $6,900 to add the advanced emission controls and to design the bulldozer to accommodate the modified engine.

EPA estimated that the average cost increase for 15 ppm sulfur diesel fuel will be seven cents per gallon. This figure would be reduced to four cents by anticipated savings in maintenance costs due to low sulfur diesel.

IV. Background data and assumptions used (indicate if assistance is needed from Cumulative Effects and/or Monitoring work groups)

The Cumulative Effects group could assess how much air quality improvement would be realized from implementation of the Tier 2 through Tier 4 standards by a specified percent of rig engines in the Four Corners area, by timeframes specified in regulation or some accelerated schedule. The group could also address the number of days of visibility improvement, and the reduced flux of Nitrogen deposition.

V. Any uncertainty associated with the option (Low, Medium, High)

Low, these diesel engine standards must be met nationally by the specified dates. The primary uncertainty raised so far is related to supply of new engines sufficient to meet demand. EPA has studied the technological feasibility of the Tier 2 and Tier 3 emission standards and has determined that they are feasibility [see http://www.epa.gov/nonroad-diesel/r01052.pdf]

VI. Level of agreement within the work group for this mitigation option N.A. for complying with national regulations.

VII. Cross-over issues to the other source groups (please describe the issue and which groups
All new “non-road” diesel engines used in the Four Corners area will have to comply with these regulations.

Mitigation Option: Interim Emissions Recommendations for Drill Rigs

I. Description of the mitigation option

The following mitigation option paper is one of three that were written based on interim recommendations that were developed prior to the convening of the Four Corners Air Quality Task Force. Since the Task Force's work would take 18-24 months to finalize, and during this time oil and gas development could occur at a rapid pace, an Interim Emissions Workgroup made up of state and federal air quality representatives was formed to develop recommendations for emissions control options associated with oil and gas production and transportation. The Task Force includes these recommendations as part of its comprehensive list of mitigation options.

NOx emissions from drill rigs are significant on a year round basis and should be reduced by a requirement that rig engines meet Tier 2 standards.

- NOx emissions from rigs contribute to visibility degradation
- This recommendation is consistent with EPA Region 8's oil and gas initiative and recent Wyoming DEQ recommendations
- The requirement may be impractical for BLM to enforce

States should analyze potential initiatives to achieve emissions reductions from these sources to reduce deposition, the cumulative impacts to visibility, and to ensure compliance with the NAAQS and PSD increments.

II. Description of how to implement

NOx emission limits determined by Tier 2 would be mandatory for new rigs and voluntary for existing equipment. The agencies to enforce this would be BLM and the New Mexico and Colorado departments of environmental quality.

III. Feasibility of the Option

The feasibility of Tier 2 requirements for new rig engines has been demonstrated in commercial applications. The environmental benefits include PM and NOx reductions. The economic feasibility depends on using the technology with new rigs. The cost for replacement of an existing engine would be high since there might be no market for the used engine.

IV. Background data and assumptions used

The technology for rig engine upgrade to Tier 2 standards is based on the requirement to use Tier 2 certified diesel engines on new rigs. Under certain circumstances, upgrades might be required on older rigs as well.

V. Any uncertainty associated with the option

Tier 2 engines are currently being manufactured, but some uncertainty exists about the effectiveness of add-on controls to meet Tier 2 levels for existing rig engines.

VI. Level of agreement within the work group for this mitigation option

TBD.

VII. Cross-over issues to the other source groups

None.

Mitigation Options: Various Diesel Controls

Duel Fuel (or Bi-fuel) Diesel and Natural Gas; Biodiesel; PM Traps; Free Gas Recirculation; Fuel Additives; Liquid Combustion Catalyst; Lean NOx Catalyst; Low NOx ECM - Engine Electronic Control Module (ECM) Reprogram; Exhaust Gas Recirculation (EGR)

I. Description of the mitigation options

Duel fuel (or Bi-fuel) diesel and natural gas

This system allows engines to run on a blend of diesel and natural gas fuels. The systems consist of an air to fuel (AFR) controller and a fuel mixing chamber. The AFR constantly adjusts the fuel to air mixture being delivered to the piston chambers and optimizes the stoichiometric relationship in order to balance the NOx and CO emissions. The mixing chamber establishes the diesel to natural gas mixing ratio. This system is being tested on drill rig diesel engines in the Pinedale, WY area. There are preliminary results based on tests of three engines (Cat 398 & 399) Pros: Operators reported that rig engine fuel costs were reduced by ~ $700 per day, requires minimal engine modification, and has a small footprint. Cons: Does not conclusively reduce NOx, increases CO and HC emissions, and the system needs frequent oversight to ensure operation.

Biodiesel

Biodiesel fuel stock comes from vegetable oil, animal fats, and waste cooking oils. Biodiesel can be blended at different percentages up to100% (typically 5 – 20%). Biodiesel at a 20% blend can reduce PM mass emissions by up to 10%, reduce HC and CO up to 20%, and may slightly increase NOx emissions. Use of biodiesel requires little or no modification to fuel system or engine. Cold temperatures require special fuel handling such as additives or heating fuel system. EPA listed "verified retrofit technology."

PM Traps

Diesel particulate filters (DPFs) collect or trap PM in the exhaust. DPFs consist of a filter encased in a steel canister positioned in the exhaust system. DPFs need a mechanism to remove the PM (regeneration or cleaning) and to monitor for engine backpressure. DPFs types have different reduction capabilities and applications. DPFs can be used in conjunction with catalysts (catalyst based (CB) DPFs) to obtain the most effective PM control for a retrofit technology. CB-DPFs can have over 90% PM mass reduction and over 99% carbon based PM reduction. CB-DPFs can also control CO and HC resulting in near elimination of diesel smoke and odor.

Flow through filters (FTFs), or partial flow filters, use a variety of media and regeneration strategies. The filter media can be either wire mesh or pertubated path metal foil. FTFs are a relatively new technology. FTF can be catalyzed or used in combination with Diesel Oxidation Catalysts (DOCs) or Fuels Borne Catalysts (FBCs). PM reduction efficiencies range from 25 to over 60% depending on the type of technology and duty/test cycle. FTFs have the potential for greater application than conventional DPFs. Some designs can be used on engines fueled with < 500 ppm sulfur fuel but efficiency decreases. Has the potential for use on older engines, but high PM levels can overwhelm even a FTF system. Adequate exhaust temperatures are needed to support filter regeneration.

Diesel exhaust PM traps are EPA listed "verified retrofit technology."

Free Gas Recirculation

Crankcase emissions from diesel engines can be substantial. To control these emissions, some diesel engine manufacturers make closed crankcase ventilation (CCV) systems, which return the crankcase blow-by gases to engine for combustion. CCV systems prevent crankcase emissions from entering the atmosphere. Aftermarket open crankcase ventilations (OCV) are available which provide incremental improvements over engines with no crankcase controls, but they still allow crankcase emissions to be released into the atmosphere. A retrofit CCV crankcase emission control (CCV) system has been introduced and verified for on-road applications by both the U.S EPA and CARB. Crankcase emissions range from 10% to 25% of the total engine emissions, depending on the engine and the operating duty cycle. Crankcase emissions typically contribute to a higher percentage (up to 50%) of total engine emissions when the engine is idling. The combined CCV/DOC system controls PM emissions by up to 33%, CO emissions by up to 23% and HC emissions by up to 66%.

Fuel Additives

Fuel additives are chemical added to the fuel in small amounts to improve one or more properties of the base fuel and/or to improve the performance of retrofit emission control technologies. Several cetane enhancers have been verified by EPA that reduce NOx 0 to 5%. Other additives are undergoing verification. There thousands of fuel additives on the market that have no emission or fuel efficiency benefit so it is important to verify the manufacturer's claims regarding benefits. EPA listed "verified retrofit technology."

Liquid Combustion Catalyst

Fuels borne catalyst systems (FBCs) are marketed as a stand-alone product or as part of a system combined with DPFs, FTFs, or DOCs. FBCs have included cerium, cerium/platinum copper, iron/strontium, manganese and sodium. A DPF must be used to collect the catalyst additive so it cannot be emitted to the air. A FBC/DOC system has been verified by EPA to reduce PM 25 – 50%, NOx 0 – 5%, and HC 40 – 50%. A FBC/FTF system has been verified by EPA to reduce PM 55 – 76%, CO 50 – 66%, and HC 75 – 89%. The estimated cost of the verified FBC is approximately $.05 per gallon. Pre-mixed fuel is recommended for retrofit applications. FBCs do not require ultra low sulfur diesel and work with a wide range of engine sizes and ages. EPA listed "verified retrofit technology."

Lean NOx Catalyst

Lean NOx catalyst (LNC) is a flow through catalyst technology similar to diesel oxidation catalyst that is formulated for NOx control. It typically uses diesel fuel injection ahead of the catalyst to serve as NOx reduction. Lean NOx catalyst can achieve a 10% to over 25% NOx reduction. It can be combined with diesel oxidation catalyst (DOC) or diesel particulate filter (DPF). Over 3500 vehicles and equipment have been retrofitted with Lean NOx catalyst and CB-DPF filter systems in United States. The sulfur lever level of the fuel has to be less than 15 ppm. Verified LNC systems use injected diesel fuel as the NOx reducing agent and as a result a fuel economy penalty of up to 3% has been reported**.** EPA listed "potential retrofit technology."

Low NOx ECM - Engine electronic control module (ECM) reprogram

Some engine manufacturers used ECM on 1993 through 1996 heavy-duty diesel engines that caused the engine to switch to a more fuel-efficient but higher NOx mode during off cycle engine highway cruising. As part of the manufacturers' requirements to rebuild or reprogram older engines (1993-1998) to cleaner levels, companies developed a heavy-duty diesel engine software upgrade (known as an ECM "reprogram", "reflash" or "low NOx" software) that modifies the fuel control strategy in the engine's ECM to reduce the excess NOx emissions. Low NOx ECM is available as a retrofit strategy to reduce NOx emissions from certain diesel engines. Emissions control performance is engine specific. A system verified for a Cummins engine by CARB provided 85% particulate and 25% oxidation reductions. Over 60,000 heavy-duty diesel engines have received ECM reprograms. CARB plans to require ECM reprogramming on approximately 300,000 to 400,000 engines. ECM application is limited to heavy-duty diesel engines with electronic controls. Most off-road engines are not equipped with electronic controls. ECM is available throughout the U.S. through engine dealers and distributors. The software can be installed on-site and the reprogram takes approximately 15 to 30 minutes.

Exhaust Gas Recirculation (EGR)

The EGR system used in retrofit applications employs low-pressure. Original Equipment EGR systems typically employ high-pressure. EGR as a retrofit strategy is a relatively new development but has been proven durable and effective over the last few years. In the U.S. retrofit low-pressure EGR systems is combined with a CB-DPF to allow the proper functioning of the EGR component. EGR can reduce the NOx formed by the CB-DPF. EGR/DPF systems have been verified by CARB. Over 3000 and exhaust gas recirculation diesel particular filter systems have been retrofitted onto on road vehicles worldwide. EGR/DPF systems can be applied to off-road engines. However, experience is limited and the off-road market not the primary target application in the U.S. Current experience with EGR/DPF systems has been a range of 190 horsepower to 445 horsepower. The fuel economy penalty from EGR component ranges from 1% to 5% based on technology designed to particular engine and the test/duty cycle. EPA listed "potential retrofit technology."

II. Description of how to implement

These controls would be voluntary retrofits for existing engines. Some of these controls may be used by engine manufacturers to meet EPA's diesel standards for new engines.

III. Feasibility of the option

A. Technical
B. Environmental
C. Economic

See the individual control summary descriptions above. For more detailed information consult Volume 2 of the WRAP Off-road Diesel Retrofit Guidance Document, to be found at:
http://www.wrapair.org/forums/msf/projects/offroad_diesel_retrofit/Offroad_Diesel_Retrofit_V2.pdf

IV. Background data and assumptions used

As EPA verified retrofits or potential retrofits (with the exception of the bi-fuel option), the data and assumptions associated with this option have been evaluated and considered. See EPA's Voluntary Diesel Retrofit Program web pages (http://www.epa.gov/otaq/retrofit/retroverifiedlist.htm and http://www.epa.gov/otaq/retrofit/retropotentialtech.htm) and Volume 2 of the WRAP Off-road Diesel Retrofit Guidance Document, located at:
http://www.wrapair.org/forums/msf/projects/offroad_diesel_retrofit/Offroad_Diesel_Retrofit_V2.pdf for more information on these verified and potential retrofit controls.

V. Any uncertainty associated with the option

Low to high uncertainty depending on the application, engine, operating conditions. These are EPA verified or potential retrofits for diesel engines (with the exception of the bi-fuel option), but some controls are limited to specific applications.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

All existing or newly introduced diesel engines (on-road, non-road, and stationary) used in the 4 Corners area could utilize these control options with the limitations noted above.

ENGINES: TURBINES

Mitigation Option: Upgrade Existing Turbines to Improved Combustion Controls (Emulating Dry LoNOx Technology)

I. Description of the mitigation option
This option involves upgrading older units with improved electronic combustion control technology that approaches or meets Dry LoNOx for existing turbines and requires Dry LoNOx technology on all new turbines. The benefits of this mitigation option are lower NOx emissions, but it is an expensive option that may take several years to implement and may be difficult to achieve with some engine models. The tradeoffs is that a few people may spend a lot of money and not significantly impact overall nitrogen oxide emissions to meet the region's emission control objectives.

II. Description of how to implement
A. Mandatory or voluntary: Implementation should be assumed as voluntary until the existing turbine population is better understood.

Differing Opinion: The best technology should be mandatory.

B. Indicate the most appropriate agency(ies) to implement Federal, state, and tribal agencies responsible for air emissions compliance.

III. Feasibility of the option
A. Technical Individual turbine assessment will be needed to confirm appropriate size or design limitations (not all turbines can be retrofitted).
B. Environmental The benefits of a dry LoNOx emissions control technology on air emissions has been proven repeatedly for many large turbines.
C. Economic The economic impact cannot be understood without an inventory of installed turbines.

IV. Background data and assumptions used
No assumptions have been made at this time on the impact of emissions reductions due to the uncertainty of the existing turbine population.

V. Any uncertainty associated with the option High.

VI. Level of agreement within the work group for this mitigation option High.

VII. Cross-over issues to the other source groups
The impact of implementing this option may be further evaluated by the Cumulative Effects or Monitoring groups.

EXPLORATION & PRODUCTION: TANKS

Mitigation Option: Best Management Practices (BMPs) for Operating Tank Batteries

I. Description of the mitigation option
This option involves implementing and/or adoption of various Best Management Practices (BMPs) for operating tanks that contain crude oil and condensate. The specific BMPs include the use of Enardo valves, closing thief and other tank hatches, maintaining valves in leak-free condition, closing valves, etc. so as to minimize VOC losses to the atmosphere.

Economic burdens are minimal since these practices are largely followed and considered a normal cost of doing business as part of responsible operations.

There should not be any environmental justice issues associated with following these practices in socio-economically disadvantaged communities.
Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement
A. Mandatory or voluntary: The implementation of measures to implement BMPs for operating tank batteries are envisioned as "voluntary" measures to enhance operating efficiency and could be easily incorporated as a BMP in voluntary programs such as the NMED San Juan VISTAS program and EPA's Natural Gas STAR Program. There are currently no mechanisms or rules to require BMPs as standards, and this seems implausible as a mandatory approach. Many companies have BMPs in place already.

B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option
A. Technical: The use of BMPs for operating tank batteries is technically feasible as is software to maximize routing efficiency.
B. Environmental: The environmental benefits of reduced VOC pollution are well documented.
Differing opinion: Quantification of emission reductions from implementation of this mitigation option is not possible.
C. Economic: These BMPs need to be explored by individual companies as to their economic viability.

IV. Background data and assumptions used
1. Tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the lack of pipeline infrastructure to pipe the fluids directly to refineries.
2. Oil and gas producing companies will need to educate their workforce on the validity and importance of these BMPs.
3. Employees will not react adversely to following these practices as a normal course of being a lease operator.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option
General agreement within working group members that this is viable and probable.

Mitigation Option: Installing Vapor Recovery Units (VRU)

<u>I. Description of the mitigation option</u>

This option involves using Vapor Recover Units (VRUs) on crude oil and condensate tanks so as to capture the flash emissions that result when crude oil or condensate is dumped into the tank from the production separator. The air quality benefits would be to minimize VOC losses to the atmosphere and if sufficient flash gas were present, there would be economic benefits as well.

Economic burdens are substantial since these units are costly to install and maintain.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.
Differing opinion: This conclusion requires adequate support that is not included in this option.

<u>II. Description of how to implement</u>

<u>A. Mandatory or voluntary:</u> The implementation of measures to implement VRUs for operating tank batteries are envisioned as "voluntary" measures since the feasibility of VRUs in the Four Corners area is negative. In certain areas of the country where ozone non-attainment areas exist, VRUs are commonly mandated by the respective Air Quality Control agency as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER). Since the Four Corners area is not in ozone non-attainment and the costs economics will not generally justify installation of VRUs for economic benefit, a voluntary approach is recommended.
<u>B. Indicate the most appropriate agency(ies) to implement</u>**:** The states.

<u>III. Feasibility of the option</u>

<u>A. Technical:</u> The use of VRUs for operating tank batteries is technically feasible.
Differing opinion: However, installation of a VRU to most existing tank installations is not likely feasible without a complete redesign and new installation. Most tanks are pressure rated at 3-5 psig and would need to be replaced with tanks designed with higher pressure rating to handle pressure surges during separator dumps. Additional pressure relief valving, pressure regulators and other safety devices would need to be included with these systems. Redesign and system replacement would need to be evaluated to determine the economic feasibility of this type of system. As these tanks are under pressure there would be additional operational and safety issues related to proper product transfer and handling. Most transporters are not equipped to handle pressurized product transfers at present. Due to the small amount of condensate produced in 4-Corners wells, the periodic "dumping" from the separators to the tanks, and the consequent uneven flash of gas from the condensate the use of VRU's is technically very challenging and may not be technically feasible. VRU's start from atmospheric pressure and boost gas to low pressure that may not be sufficient to flow into the collection system lines. In this case, they are either not feasible or would require additional compression. The lack of electricity in the fields effectively precludes any operationally feasible VRU use.

<u>B. Environmental:</u> The environmental benefits of reduced VOC pollution are well documented. Benefits are relative to production throughputs. VOC emissions from flashing emissions are a function of well pressure and condensate production. The amount of emission reduction will be proportional to the amount of uncontrolled VOC emissions. Even if VRU's can be made to work in the 4-corners area, the amount of VOC emission reduction per tank will be low due to the low condensate production rate.

<u>C. Economic:</u> The use of VRUs for recovering the flash emissions from produced crude oil/condensate are economically feasible where the Gas Oil Ratio (GOR) from produced crude oil/condensate is high and the daily production volume is at least 50 barrels/day or greater. Most wells in the Four Corners area typically produce less than 1 bbl/day of crude oil or condensate so VRUs are not economically feasible.

Flares or combustors could be considered an alternative control technology if sufficient VOC emissions exist. At 1 bbl/day and low pressure drop the flash gas volume and VOC content will not justify control systems.

IV. Background data and assumptions used

1. Tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the lack of pipeline infrastructure to pipe the fluids directly to refineries.
2. The minimal production levels for most wells make the use of VRU economically infeasible.

V. Any uncertainty associated with the option Low.

Differing opinion: MEDIUM based on availability of power, high maintenance requirements and reliability/performance.

Differing opinion: This would rank a high level of uncertainty in actually achieving meaningful and cost effective emission reductions using this technology.

VI. Level of agreement within the work group for this mitigation option

General agreement within working group members that the use of VRUs in the Four Corners areas is economically infeasible and an unlikely source for voluntary adoption.

Mitigation Option: Installing Gas Blankets Capability

I. Description of the mitigation option
This option involves modifying existing and installing new designed crude oil and condensate tanks that would be capable of placing an inert gas blanket over these tanks to minimize vapor loss. The inert gas would fill the space above the condensate/crude oil to minimize volatilization and vapor loss. The air quality benefits would be to minimize VOC losses to the atmosphere and if sufficient flash gas if present, there would be economic benefits as well.

Economic burdens are substantial since these units are costly to install and maintain.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.
Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement
A. Mandatory or voluntary: The implementation of measures to implement gas blankets for operating tank batteries are envisioned as "voluntary" measures since the feasibility of gas blanket technology in the Four Corners area is negative. In certain areas of the country where ozone non-attainment areas exist, gas blanket technology is one of several measures commonly mandated by the respective Air Quality Control agency as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER). Since the Four Corners area is not in ozone non-attainment and the cost economics will not generally justify installation of gas blankets for economic benefit, a voluntary approach is recommended.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option
A. Technical: The use of gas blankets for operating tank batteries is technically feasible but requires the tanks to be designed to handle the increased pressures that will result when crude oil/condensate enters the tank, thereby pressurizing the gas blanket. Currently crude oil/condensate tanks are designed as atmospheric tanks and are designed only to withstand 5 psig of internal pressure. API 12F specifies 16 oz of pressure for normal operation and no greater than 24 oz for emergency operations. Using gas blanket technology requires such tanks to withstand about 100 psig, which increases the costs for tanks substantially. As these tanks are under pressure there would be additional operational and safety issues related to proper product transfer and handling. Most transporters are not equipped to handle pressurized product transfers at present.
B. Environmental: The environmental benefits of reduced VOC pollution are well documented.
Differing opinion: If this is considered a candidate control technology, the detailed engineering and economic analyses are needed to evaluate the cost to control relative to other potential control measures.
C. Economic: The use of gas blanket technology for preventing the release of flash and vapor emissions from produced crude oil/condensate are economically feasible for large, centrally located tank batteries where the crude oil/condensate can be piped from numerous wells to a centralized facility. Most wells in the Four Corners area typically produce less than 1 bbl/day of crude oil or condensate so the use of pipelines to transport the crude oil/condensate to a centralized facility is uneconomic.

IV. Background data and assumptions used
1. Individual tank batteries rather than large, centralized tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the minimal daily production volumes (i.e., less than 1 barrel/day).

V. Any uncertainty associated with the option Low.

Differing opinion: HIGH based on feasibility comments above and additional regulatory requirements for pressurized vessels, transport of pressurized product, and added safety processes.

VI. Level of agreement within the work group for this mitigation option

General agreement within working group members that the use of gas blanket technology in the Four Corners areas is economically unfeasible and an unlikely source for voluntary adoption.

Mitigation Option: Installing Floating Roof Tanks on Tanks in the Four Corners Region

I. Description of the mitigation option

This option involves using floating roof tanks on crude oil and condensate tanks so as to prevent the loss of emissions that result from crude oil or condensate stored in the tank. The air quality benefits would be to minimize VOC losses to the atmosphere and if sufficient gas were present, there would be minimal economic benefits. However, the use of floating roof tanks on smaller tanks instead of fixed roof tanks do not reduce the emissions. The emissions actually increase.

Economic burdens are substantial since these units are costly to install and maintain.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to implement floating roof tanks on tank batteries are envisioned as "voluntary" measures since the feasibility of floating roof tanks in the Four Corners area is negative. At certain facilities in the country where tanks are considerably larger are commonly mandated by the respective Air Quality Control agency as BACT or LAER. The common sizes of tanks in the Four Corners area will not benefit economically or in emission reductions through installation of floating roof tanks. Generally, emissions will increase if floating roofs are installed on these small tanks. Therefore, this mitigation does not have merit for the Four Corners area and is recommended not to be implemented either voluntary or mandatory.
B. Indicate the most appropriate agency (ies) to implement**:** NMED, Colorado Air Pollution Control Division.

III. Feasibility of the option

A. Technical: The use of floating roof tanks on tank batteries is technically feasible, however, not currently available for smaller sized tanks.
B. Environmental: The environmental benefits of reduced VOC pollution are well documented for larger tanks; however the documentation on smaller tanks with fixed roofs indicates an increase in emissions.
C. Economic: The use of floating tank roofs for preventing the working loss emissions from produced crude oil/condensate is not economically feasible.

IV. Background data and assumptions used

1. Tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the lack of pipeline infrastructure to pipe the fluids directly to refineries.
2. The minimal production levels for most wells make the use of floating rank roofs economically infeasible.

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option.

General agreement within working group members is that the use of floating tank roofs in the Four Corners areas is economically infeasible and an unlikely source for voluntary adoption.

EXPLORATION & PRODUCTION: DEHYDRATORS/SEPARATORS/HEATERS

Mitigation Option: Replace Glycol Dehydrators with Desiccant Dehydrators

I. Description of the mitigation option

Desiccant dehydrators utilize moisture-absorbing salts to remove water from natural gas. Desiccants can be a cost-effective alternative to glycol dehydrators. Additionally, there are only minor air emissions from desiccant systems.

Desiccant dehydrators are very simple systems. Wet gas passes through a "drying" bed of desiccant tablets (e.g., salts such as calcium, potassium or lithium chlorides). The tablets pull moisture from the gas, and gradually dissolve to form a brine solution. Maintenance is minimal - the brine must be periodically drained to a storage tank, and the desiccant vessel must be refilled from time to time. Often, operators will utilize two vessels so that one can be used to dry the gas when the other is being refilled with salt.

Desiccant dehydrators have the benefit of greatly reducing air emissions. Conventional glycol dehydrators continuously release methane, volatile organic compounds (VOC) and hazardous air pollutants (HAP) from reboiler vents; methane from pneumatic controllers; CO_2 from reboiler fuel; and CO_2 from wet gas heaters. The only air emissions from desiccant systems occur when the desiccant-holding vessel is depressurized and re-filled – typically, one vessel volume per week.[1] Some operators have experienced a 99% decrease in CH_4/VOC/HAP emissions when switching over to a desiccant system.[2]

Other potential benefits of desiccant dehydrators include: reduced ground contamination; reduced fire hazard; low maintenance requirements (because there are no moveable parts to be replaced and maintained); and the elimination of an external power supply.[3]

Solid desiccants are commonly used at centralized natural gas plants, but glycol dehydrators are still the most popular form of dehydration used in the field.[4] Most probably this is because there are particular conditions under which desiccant dehydrators work best:

- **The volume of gas to be dried is 5 MMcf/day or less.** Many wells in the San Juan Basin average less than 5 MMcf/day,[5] so this should not be a constraint to using desiccant systems.
- **Wellhead gas temperature is low (< 59º F for CaCl and < 70º for LiCl)**. If the inlet temperature of the gas is too high, desiccants can form hydrates that precipitate from the solution and cause caking and brine drainage problems. It is possible to cool or compress gas to the appropriate temperatures, but this increases the cost of the desiccant system.
- **Wellhead gas pressure is high (> 250 psig for CaCl and >100 psig for LiCl).**

II. Description of how to implement

A. Mandatory or voluntary

Where feasible, it should be mandatory, since it is both cost effective and virtually eliminates air emissions from field dehydrators.

Differing opinion: Cost is prohibitive for replacement of existing systems but applicable for new installations as determined on a case-by-case evaluation.

B. Indicate the most appropriate agency(ies) to implement

Dehydration is not a down-hole issue, therefore, is not the sole purview of the oil and gas commissions. Furthermore, this option relates specifically to minimizing air emissions. Thus, the most appropriate agencies to implement this option would be the environment/health agencies in the different states.

Differing opinion: The Federal area source MACT rules address glycol dehydrators and require controls for those whose size and throughputs justify control. This regulation was carefully considered and evaluated by EPA prior to finalization and should not be exceeded without careful analysis and justification.

III. Feasibility of the option

A. Technical

Desiccant dehydration is currently feasible under certain operating conditions (i.e., temperature and pressure of inlet gas). It may be possible to expand the applicability with add-on technologies (e.g., auto-refrigeration units to chill the inlet gas).[6]

Differing opinion: On March 20, 2007 at the NMOCD Greenhouse Gas meeting held in Santa Fe, NM, an operator stated during his presentation that based on their company's experience with salt dehydration in Wyoming, they are removing all salt dehydrators from service. Although the economics and technical feasibility initially looked very favorable, they have found salt slippage and other operational concerns very problematic with no technical solutions to date. Thus this method of dehydration is currently not as viable for their operations. This technology needs to be thoroughly considered before adoption – although it looks good initially, long-term use has not proven to be sustainable.

B. Environmental

Under some environmental conditions (e.g., high temperatures) this option becomes less feasible. Wastewater by product would need to handled, disposed of or re-injected. In the CBM areas of Colorado the gas is predominately methane and the gas is relatively dry and requires little dehydration. In this case VOC emissions are minimal. Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required. As a result of the type of production in this region it is likely that dehydration emissions are not significant and the use of such alternative technology may not be warranted.

C. Economic

For new dehydration systems, desiccant systems have been shown to be a lower cost alternative (both for capital and operating costs) than glycol dehydrators.[7] The payback period to replace an existing glycol dehydrator with a desiccant system has been shown to be less than 3 years.[8] The economics stated are only valid for a small range of temperature, pressure, and water content combinations. Desiccant dehydration for hot, low pressure, or high water content gas streams is not cost effective when compared to glycol dehydration.

Differing opinion: Increased operational costs for the desiccant, storage, and handling/disposal of wastewater should be factored in to the economics.

IV. Background data and assumptions used See endnotes.

V. Any uncertainty associated with the option Low.

Differing opinion: MEDIUM-HIGH based above comments regarding generation of wastewater, disposal, and recent operational experiences in Wyoming.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other Task Force work groups

Notes:

1. U.S. Environmental Protection Agency. Natural Gas STAR Program. "Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators." p. 5. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf

2. U.S. Environmental Protection Agency. Natural Gas STAR Program. “Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators.” p. 1. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf
3. Acor, L. Design Enhancements to Eliminate Sump Recrystalization in Zero-Emissions Non-Regenerative Desiccant Dryer. In: The Tenth International Petroleum Environmental Conference, Houston, TX. November 11-14, 2003 http://ipec.utulsa.edu/Conf2003/Papers/acor_78.pdf
4. Smith, Glenda, American Petroleum Institute, written comments to Dan Chadwick, USEPA/OECA, September 22, 1999. In. EPA Office of Compliance. Oct. 2000. Sector Notebook Project - Profile of the Oil and Gas Extraction Industry. EPA/310-R-99-006. p. 31
5. Lippman Consulting. May 16, 2005. “Production levels increase in San Juan Basin,” Energy Quarterly. http://www.businessjournals.com/ artman/publish/article_898.shtml
6. U.S. EPA. Natural Gas Star. Replace Glycol Dehydrator with Separators and In-Line Heaters. PRO Fact Sheet No. 204.
   http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/replaceglycoldehydratorwithseparators.pdf
   Auto-refrigeration has been used in other oilfield applications, such as chilling gas to enhance water condensation and separation.
7. U.S. Environmental Protection Agency. Natural Gas STAR Program. “Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators.” p. 16. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf
   For a system processing 1 MMcf/day natural gas, operating at 450 psig and 47 F:
   Total implementation (capital plus installation): $22,750 (desiccant) vs. $35,000 (glycol)
   Total annual operating costs: $3,633 (desiccant) vs. $4,847 (glycol)
8. U.S. Environmental Protection Agency. Natural Gas STAR Program. “Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators.” p. 17. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf
   This payback period was reported for a glycol dehydrator system that was replaced with a two-vessel desiccant dehydration system.

Mitigation Option: Installation of Insulation on Separators

I. Description of the mitigation option

This option involves modifying existing and installing new separators that are insulated so as to reduce fuel usage. The air quality benefits would be to minimize combustion emissions to the atmosphere (NOx, CO, NMHC).

Economic burdens are significant but not insurmountable if the cost recovery factor from reduced fuel usage over the anticipated life of the unit shows a positive return on investment.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.
Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to implement insulated separators and vessels are envisioned as "voluntary" measures since the feasibility of installing insulation on new units or retrofitting existing units must be evaluated for a positive Net Present Value (NPV) or Return on Investment (ROI) in the Four Corners area. If the NPV or ROI meets a company's investment targets, then utilization of this technology should be encouraged as a best practice. There are no existing mandates by the respective Air Quality Control agencies to require insulated vessels as BACT. Since the Four Corners area is not in ozone non-attainment and the cost economics will not always justify installation of insulation for economic benefit, a voluntary approach is recommended.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option

A. Technical: The application of insulation to separators, tanks, or other heated vessels is technically feasible. Currently some companies are insulating newly installed on production separators and larger produced water tanks on a case-by-case basis.
B. Environmental: The environmental benefits of reduced NOx, CO, and NMHC pollution are well documented.
Differing opinion: It is unclear how much insulation would cut fuel consumption and consequently reduce emissions. The emissions from well-site production units are very small (the units are very small) and not a significant component of the regional NOx budget. Insulation of these units would make a small reduction in a very small number.
C. Economic: The application of insulation to separators, tanks, or other heated vessels for reducing fuel usage and minimizing combustion emissions from separators, tanks, or other heated vessels are economically feasible where the there is payback that meets the respective companies targets for investments (i.e., ROI or NPV). For older units or vessels where the remaining life of the equipment is limited, the economics may not justify the application of insulation. Costs basis and frequency of maintenance and ultimate replacement of both blown and wrapped insulation should be identified.

IV. Background data and assumptions used

Most fired units in the Four Corners area are utilized during the time period from November through March to achieve their objective.

V. Any uncertainty associated with the option (Low, Medium, High) Low.
Differing opinion: High in terms of emission reductions.

VI. Level of agreement within the work group for this mitigation option TBD.

Mitigation Option: Portable Desiccant Dehydrators

I. Description of the mitigation option

Desiccant dehydrators utilize moisture-absorbing salts (e.g., calcium, potassium or lithium chlorides) to remove the water from natural gas.

Glycol dehydrators may be more suitable than desiccant systems in some field gas dehydration situations (e.g., when inlet gas has a high temperature and low pressure). But glycol dehydrators require regulator maintenance for optimal performance. During maintenance periods production wells are either shut-in or vented to the atmosphere (rather than running wet gas into the pipeline). Venting is especially popular for low-pressure wells, because it can be difficult to resume gas flow once they are shut in.

Portable desiccant dehydrators can be brought on-site during glycol dehydrator maintenance (or break-down) periods. This allows the gas to be processed and sent to the pipeline, rather than requiring the well to be shut-in, or the gas to be vented. These portable dehydrators can also be used to capture and dehydrate gas during “green completion” operations.

The benefits of utilizing portable desiccant dehydrators are: the ability to continue producing a well during glycol dehydrator maintenance; the elimination of methane, VOCs and HAPs that would otherwise be vented while glycol dehydrators are being serviced.

II. Description of how to implement

A. Mandatory or voluntary

Voluntary at this point in time. There are technologies that would result in much more significant air emissions reductions that should have higher regulatory priority.

Differing opinion: On March 20, 2007 at the NMOCD Greenhouse Gas meeting held in Santa Fe, NM, an operator stated during his presentation that based on their company’s experience with salt dehydration in Wyoming, they are removing all salt dehydrators from service. Although the economics and technical feasibility initially looked very favorable, they have found salt slippage and other operational concerns very problematic with no technical solutions to date. Thus this method of dehydration is currently not as viable for their operations.

B. Indicate the most appropriate agency(ies) to implement

Environment/Health Departments, which have the responsibility for the regulation of air quality.

III. Feasibility of the option

A. Technical

A portable desiccant dehydrator requires a truck that has been modified to house the dehydrator; and ancillary equipment (e.g., piping) to re-route gas flow from the glycol to the desiccant dehydrator. See the discussion of technical feasibility in the desiccant dehydration option paper – the same comments and issues apply here.

B. Environmental

Desiccant dehydration systems work best under certain gas temperature and pressure conditions. Wastewater by product would need to handled, disposed of or re-injected. In the CBM areas of Colorado the gas is predominately methane and the gas is relatively dry gas and requires little dehydration. In this case VOC emissions are minimal. Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required. As a result of the type of production in this region it is likely that dehydration emissions are not significant and the use of such alternative technology may not be warranted.

C. Economic

Capital cost of a 10-inch portable desiccant dehydrator is estimated to be greater than $4,000. Operating costs (e.g., labor, transportation, set-up and decommissioning) are on the order of $5,000/yr.

Differing opinion: Cost is prohibitive for replacement of existing systems but applicable for new installations as determined on a case-by-case evaluation. Increased operational costs for the desiccant, storage, and handling/disposal of wastewater should be factored in to the economics.

One operator reports that portable desiccant dehydrators are economical when used on gas wells that produced more than 15.6 Mcf/day.

Obviously, a company would get the most economic benefit from owning this equipment if the equipment was kept in continual operation – i.e., moved from one site immediately to another.

IV. Background data and assumptions used
All information in this mitigation option comes from: U.S. EPA. *Portable Desiccant Dehydrators.* PRO Fact Sheet No. 207. Available at: http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/portabledehy.pdf

V. Any uncertainty associated with the option TBD.
Differing opinion: MEDIUM-HIGH based above comments regarding generation of wastewater, disposal, and recent operational experiences in Wyoming.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None at this time.

Mitigation Option: Zero Emissions (a.k.a. Quantum Leap) Dehydrator

I. Description of the mitigation option

Conventional glycol dehydrators route natural gas through a contactor vessel containing glycol, which absorbs water (and VOCs, HAPs) from the gas. Typically, gas-driven pumps are then used to circulate glycol through a reboiler/stripper column, where it is regenerated, then sent back to the contactor vessel. Distillation and reboiling removes VOCs, HAPs and absorbed water from the glycol, and releases these compounds through the "still column" vent as vapor. Conventional glycol dehydrators vent directly to the atmosphere. Add-on technologies, such as thermal oxidizers, can reduce the amount of methane and VOCs that are vented, but result in increased NO_x, particulate matter and CO emissions.[1]

Natural gas dehydration is the third largest source of methane emissions and causes more than 80% of the natural gas industry's annual HAP and VOC emissions.[2] In the CBM areas of Colorado the gas is predominately methane and the gas is relatively dry gas and requires little dehydration. In this case VOC emissions are minimal. Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required. As a result of the type of production in this region it is likely that dehydration emissions are not significant and the use of such alternative technology may not be warranted.

The zero emissions dehydrator combines several technologies that lower emissions. These technologies eliminate emissions from glycol circulation pumps, gas strippers and the majority of the still column effluent.

- Rather than being released as vapor, the water and hydrocarbons are collected from the glycol still column, and the condensable and non-condensable components are separated from each other. The two primary condensable products are wastewater, which can be disposed of with treatment; and hydrocarbon condensate, which can be sold. The non-condensable products (methane and ethane) are used as fuel for the glycol reboiler, instead of releasing them to the atmosphere.
- A water exhauster is used to produce high glycol concentrations without the use of a gas stripper.
- Methane emissions are further reduced by using electric instead of gas-driven glycol circulation pumps.

Benefits of this technology include:

- Elimination of methane emissions.[3]
- Elimination of virtually all VOCs (reduction from multiple tons per year to pounds per year.[4]
- Has a HAP destruction efficiency of greater than 99%.[5]
- Reduces emissions of particulate matter, sulfur dioxide, NO_x or CO emissions (these compounds are emitted when thermal oxidation, a competing method of reducing glycol dehydrator VOC emissions, is used).
- Eliminates the Kimray pump, which is typically used to circulate glycol. Kimray pumps require extra gas (which is eventually vented to the atmosphere) for pump power.[6]
  - Significantly reduces fuel requirements for glycol reboiler. Natural gas that was used for this purpose can now be sent to market.
  - Results in collection of condensate, which can be sold.

II. Description of how to implement

A. Mandatory or voluntary

The zero emissions dehydrator system offers incredible reductions in emissions. States that are experiencing air quality problems could make this a mandatory technology, and achieve large reductions in VOC, HAP and methane emissions.

Differing opinion: Previous statement requires supporting documentation and quantification of 'trade-off' pollutants.
B. Indicate the most appropriate agency(ies) to implement
Dehydration is not a down-hole issue, therefore, is not the sole purview of the oil and gas commissions. Furthermore, this option relates specifically to minimizing air emissions. Thus, the most appropriate agencies to implement this option would be the environment/health agencies in the different states.

III. Feasibility of the option
A. Technical
The operation of the glycol circulation pump requires electric utilities or an engine generator set. The use of electric pumps (rather than fossil fuel driven pumps) will minimize NO_x, CO, CO_2, SO_2 emissions at the wellhead, but will result in some emissions at electrical generation source (e.g., coal-fired power plant).

Zero emissions dehydrators can be newly installed, and existing dehydrators can be retrofitted by modifying the gas stream piping and using a 5 kW engine-generator for electricity needs.[7] This requires a fuel or power source, for which associated emissions need to be quantified.

B. Environmental
Environmental benefit for this mitigation option needs to be defined.

C. Economic[8]
Capital costs of a zero emissions dehydrator are similar to the costs of installing a conventional dehydrator equipped with a thermal oxidizer (>$10,000). Operating and Maintenance costs are greater than $1,000 per year, but lower than the maintenance costs for conventional glycol dehydrators.

If operators were to install zero emissions dehydrators, EPA estimates that the payback to occur in less than a year.
Differing opinion: This presumes the ability to recover the hydrocarbons for sales – which is not without significant challenges and technical difficulties.

IV. Background data and assumptions used

The calculations of methane, VOC and HAP emissions from the zero emissions dehydrator were based on a dehydrator that processed 28 MMcf/day.[9] Other assumptions are contained in the endnotes.

If we had emissions data for glycol dehydrators from the San Juan Basin, we could provide a more accurate (and basin-specific) comparison of methane, VOC and HAP emissions from conventional dehydrators versus emissions from zero emissions dehydrators.

V. Any uncertainty associated with the option TBD.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None at this time.

Notes:
1. Permit renewal application by Centerpoint Energy Gas Transmission Co. to Louisiana Department of Environmental Quality. AI# 26802. March, 2005. Available at: http://www.deq.louisiana.gov/apps/pubNotice/show.asp?qPostID=2335&SearchText=centerpoint&startDate=1/1/2005&endDate=7/6/2006&category=

The application includes estimated emissions scenarios for controlling glycol dehydrator still column vent emissions with or without thermal oxidation.

2. McKinnon, H.W. and Piccot, S.D. 2003. "Emissions control of criteria pollutants, hazardous pollutants, and greenhouse gases, Natural Gas Dehydration, Quantum Leap Dehydrator." Environmental Technology Verification Program, Joint Verification Statement. U.S. EPA and Southern Research Institute. Available at: http://www.epa.gov/etv/pdfs/vrvs/03_vs_quantum.pdf
3. *ibid.*
4. Rueter, C.O., Reif, D.L. and Myers, D.B. 1995. Glycol dehydrator BTEX and VOC emissions testing results at two units in Texas and Louisiana. U.S. EPA Air and Energy Engineering Research Laboratory. Project No. EPA/600/SR-95/046.

   A study of two glycol dehydrators, processing 3.6 and 4.9 million standard cubic feet of gas per day, were found to have VOC emissions of approximately 19 and 37 tons of VOC/year, respectively. Tests run on the Zero Emissions Dehydrator, processing 28 million standard cubic feet of gas per day, resulted in average emissions of 0.0003 lb/h (2.6 lbs/yr). This is a dramatically lower amount of VOC emissions than conventional glycol dehydrators.
5. McKinnon, H.W. and Piccot, S.D. 2003. (See Note 2)
6. Fernandez, R., Petrusak, R., Robins, D. and Zavodil, D. June, 2005. "Cost-effective methane emissions reductions for small and midsize natural gas producers," Journal of Petroleum Technology. Available at: http://www.icfi.com/Markets/Environment/doc_files/methane-emissions.pdf
7. U.S. EPA. "Zero emissions dehydrators," PRO Fact Sheet No. 206. Available at: http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/zeroemissionsdehy.pdf
8. All of the economic information comes from: U.S. EPA. (see Note 7)
9. McKinnon, H.W. and Piccot, S.D. 2003. (See Note 2)

Mitigation Option: Venting versus Flaring of Natural Gas during Well Completions

I. Description of the mitigation option

Both venting and flaring of natural gas result in the release of greenhouse gases, hazardous air pollutants (HAPs) and others.

The venting of natural gas primarily releases methane, a greenhouse gas. Depending on the composition of the gas, venting will release other hydrocarbons such as ethane, propane, butane, pentane and hexane. In some locations, natural gas contains the EPA-designated HAPs benzene, toluene, ethyl benzene and xylenes (BTEX). Both hexane (also a HAP) and the BTEX compounds are present in San Juan Basin natural gas, typically accounting for 0.3 - 0.6 % of the natural gas composition.[1]

Differing opinion: This is only true for the conventional production. Coal bed methane does not contain appreciable amounts of VOCs or HAPs. Depending on the formation, natural gas may also contain nitrogen, carbon dioxide or sulfur compounds, such as hydrogen sulfide (H_2S), which is a highly toxic gas. In the New Mexico portion of the San Juan Basin, there are at least 375 gas wells, from at least five different producing formations, that contain hydrogen sulfide.[2]

Flaring is used as a means of converting natural gas constituents into less hazardous and atmospherically reactive compounds. The main purpose for flaring is for process safety reasons. Flaring is required when completing a well for two reasons: (1) the initial gas and liquids produced by most wells does not meet the gas gatherer's (pipeline's) quality requirements, and (2) the flare is the primary safety device in the event of an overpressure or equipment failure. The objective for both industry and the public is to minimize flaring where possible for both environmental and economic reasons. The assumption is that combustion processes associated with flares efficiently converts hydrocarbons and sulfur compounds to relatively innocuous gases such as CO_2, SO_2, and H_2O.

While industrial flares associated with processes such as refineries have the potential to be highly efficient (e.g., 98-99%), the few studies that have been conducted on oil and gas "field flares" have found much lower efficiencies (62-84%).[3] Fields flares without combustion enhancements (e.g., knockout drums to collect liquids prior to entering the flare; flame retention devices; pilots) have a much lower efficiency compared to properly designed and operated industrial flares.[4] Other factors, such as improper liquids removal,[5] low heating value of the fuel,[6] flow rate of gas,[7] and high wind speeds,[8] also decrease the combustion efficiency of flares.

Differing opinion: The one study cited is the only flare study that found low destruction efficiencies when burning production type gas streams. A number of other studies have confirmed destruction efficiencies >98% - which is the EPA guidance. A cooperative study, known as the international flare consortium study, is underway now and is testing destruction efficiencies across a wide range of gas types, flare types, and conditions.

There is a dearth of information on combustion efficiencies for flares used during well completion events, but given the fact that these flares are more rudimentary than industrial or even solution gas flares, it is highly possible that they have even lower combustion efficiencies.

Differing opinion: There are a number of very well done flare studies published.

When flares burn inefficiently, a host of hydrocarbon by-products that include highly reactive VOCs and polycyclic aromatic hydrocarbons, may be formed.[9] Leahey et al. (2001) found more than 60 hydrocarbon by-products, including known carcinogens such as benzene, anthracene and benzo(a)pyrene, downwind of a natural gas flare estimated to be operating at 65% combustion efficiency.[10] The inefficient burning of hydrocarbons also produces soot (particulate matter).[11] Additionally, nitrogen oxides are formed during the combustion process, even if the flare gas does not contain nitrogen.[12]

Differing opinion: The one study cited is the only flare study that found low destruction efficiencies when burning production type gas streams. A number of other studies have confirmed destruction efficiencies >98% - which is the EPA guidance. A cooperative study, known as the international flare consortium study, is underway now and is testing destruction efficiencies across a wide range of gas types, flare types, and conditions.

See the Endnotes for a table that summarizes the potential health and environmental effects related to compounds released during flaring and venting.[13]

Differing opinion: Not having access to the original table(s), it appears that errors may have occurred when it was adapted given the unwarranted combination of gas constituents and combustion products in one table and some obvious flaws (i.e., VOCs, SO2 and NOx contributing to particulate pollution but not aggravating respiratory conditions).

Flares operated during well completion activities handle enormous volumes of gas, which is either vented or flared over a short period of time. The amounts of HAPs and VOCs produced during a typical well completion in Wyoming have been calculated. It has been estimated that a single well completion event, which lasts an average of 10 days, releases:

- 115 tons of VOCs, and 4 tons of HAPs (assumption: 100% venting); or
- *86* tons VOCs, and *3* ton HAPs (assumption: half of the gas is flared per completion, and the flare operates at 50% efficiency).[14]

Differing opinion: Many completions in Wyoming – particularly those with gas flow rates in the 4 MMSCF/day range suggested above – are completed using flareless completion techniques which significantly reduces volume flared (75 to 90% reduction). However, use of these techniques is limited to those areas where the reservoir pressure is high enough to clean up the well and get the gas into the pipeline.

While it is clear that flaring reduces the volume (mass) of VOCs and HAPs, questions remain, such as: what are the particular VOC and HAP compounds released during both venting and flaring; what are the concentrations of these compounds in ambient air; [15] and can well completion flares somehow be designed (e.g., better liquid removal, lower gas flow rates going to the flare) to more effectively destroy hazardous compounds.

For a true assessment of the relative benefits of flaring vs. venting (especially with respect to human health), there is a need for a better assessment of venting/flaring emissions from well completions in the San Juan Basin. This assessment should determine both volumes of emissions, and provide a characterization of VOCs, HAPs and other compounds emitted (volumes and species) during well completion venting and flaring.

II. Description of how to implement

Using methods similar to those used in Wyoming, calculations could be performed to estimate the amount of VOCs and HAPs released from flaring and venting during well completion events in the San Juan Basin. Information requirements include:

- volume of gas released (vented or flared) per well completion
- VOC and HAP weight % of the natural gas
- estimates of combustion efficiency of flares
- estimates of how often flares are extinguished (resulting in venting of gas)

Monitoring downwind of sites that are flaring and/or venting is needed, to better characterize concentrations and species of VOCs and HAPs, as well as other flaring by-products.

A. Mandatory or voluntary
Initially, it could be a voluntary initiative, but if that does not produce data or results there may need to be mandatory reporting and monitoring requirements.

B. Indicate the most appropriate agency(ies) to implement
State oil and gas commissions could require the reporting of well completion emissions volumes; and environment/health departments would be the appropriate agencies to require monitoring of venting and flaring emissions.

III. Feasibility of the option
A. Technical
Emissions volumes from well completions have been determined for Wyoming, so presumably it is technically feasible to determine volumes for the San Juan Basin. If the data do not exist, perhaps the monitoring work group could work with industry to calculate or develop estimates of these volumes specific to the San Juan Basin.

Researches in Alberta have been able to determine combustion by-products using on-site analytical equipment or through absorbent samplers for confirmatory analyses by combined gas chromatography/mass spectrometry. Flare combustion efficiency were then calculated using a carbon mass balance of combustion products identified in the emissions. See Strosher (1996), Endnote 4.

B. Environmental
None.

C. Economic
Emissions volumes from well completions: low cost.
The identification of compounds emitted during venting and combustion: unknown.

IV. Background data and assumptions used See Endnotes Section.

V. Any uncertainty associated with the option
High uncertainty: depends on willingness of industry and regulators to undertake the necessary data collection.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None.

Notes:
1. Proportions calculated based on data from: Mansell, G.E. and Dinh, T. (ENVIRON International). September 2003. Emission Inventory Report - Air Quality Modeling Analysis For The Denver Early Action Ozone Compact: Development of the 2002 Base Case Modeling Inventory. p. 3-5. http://apcd.state.co.us/documents/eac/2002%20Modeling%20EI.pdf

Table 3-5. Average gas profiles (% composition) by formation for the San Juan Basin

	Mesa Verde	Dakota	Pictures Cliffs	Gallup	
Nitrogen	0.212	1.603	0	0.965	
Carbon Dioxide	1.388	1.034	1.403	0.639	
Methane	84.372	74.979	87.736	76.944	
Ethane	8.221	12.163	6.373	10.823	
Propane	3.19	6.488	2.651	6.552	
Butanes	1.432	2,532	1,148	2.551	
Pentanes	0.727	0.765	0.418	0.948	
Hexanes	0.459	0.437	0.270	0.578	
Benzene	0.0145	0.016	0.003		
Toluene	0.00706	0.003	0.0014		
Ethyl Benzene	0.00037	0.0001	0.0002		
Xylene	0.002	0.0006	0.001		
Calculated VOC and HAP content (not in original chart)					Average for all formations
HAPS (BTEX + hexane)	0.483	0.457	0.276	0.578	0.4483
VOCs (C1-C4)	97.94	96.93	98.33	97.82	97.753

2. Hewitt, J. (Bureau of Land Management). 2005. "H2S Occurrences San Juan Basin," a presentation at Hydrogen Sulfide: Issues and Answers Workshop. http://octane.nmt.edu/sw-pttc/proceedings/H2S_05/BLM_H2S_SanJuanBasin.pdf
3. Strosher, M. 1996. Investigations of Flare Gas Emissions in Alberta. Alberta Research Council, November 1996.
Strosher (1996) found flaring efficiencies of 62-71% and 82-84% for sweet and sour gas flares, respectively. The sweet gas had a higher liquid hydrocarbon content than the sour gas being flared. Leahy et al. (2001, citation in Endnote 9) observed flare efficiencies of 68 ±7 % at sweet and sour gas flares in Alberta.
4. Seebold, J., Davis, B., Gogolek, P., Kostiuk, L., Pohl, J., Schwartz, B., Soelberg, N., Strosher, M., and Walsh, P. 2003. "Reaction Efficiency of Industrial Flares: the perspective of the past." International Flare Consortium, Combustion Canada '03 Paper. http://www.nrcan.gc.ca/es/etb/cetc/ifc/id4_e.html
5. Russell, J. and Pollack, A. (ENVIRON International). 2005. Final Project Report: Oil And Gas Emission Inventories For The Western States. Report prepared for the Western Governors' Association. Appendix A, Wyoming Emission Factor Documentation. p. A-2.
http://www.wrapair.org/forums/ssjf/documents/eictts/OilGas/WRAP_Oil&Gas_Final_Report.122805.pdf
When liquid content is too high, flares don't or won't ignite.
6. Kostiuk, L.W., M.R. Johnson & R.A. Prybysh. 2000 "Recent Research on the Emission from Continuous Flares," Paper presented at CPANS/PNWIS–A&WMA Conference (Banff, Alberta, April 10-12). Cited in: Seebold et al. (2003).
7. Strosher, M. 1996. Investigations of Flare Gas Emissions in Alberta. Alberta Research Council, November 1996. p. 85.
Combustion efficiencies decreased from 70.6% (flow rate of 1 m3/min) to 67.2 % (flow rate of 5-6 m3/min) for sweet gas being flared at an oil tank battery in Alberta.
Increasing the flow increased the volatile hydrocarbons by about 33%, and the non-volatiles by three times the concentrations found in the lower volume flow.
8. Leahey, Douglas M., Preston, Katherine and Strosher, Mel. 2001. Theoretical and Observational Assessments of Flare Efficiencies," Journal of the Air & Waste Management Association. Volume 51. p. 1615

"It has been shown, as well, that flaring can be efficient only at low wind speeds because the size of the flare flame, which is an indicator of flame efficiency, decreases with increasing wind speed. Therefore, the flaring process could routinely result, during periods of moderate to high wind speeds, in appreciable quantities of products of incomplete combustion such as anthracene and benzo(a)pyrene, which can have adverse implications with respect to air quality."
9. Seebold, J., Gogolek, P., Pohl, J., and Schwartz, R. 2004. "Practical implications of prior research on today's outstanding flare emissions questions and a research program to answer them," Paper presented at the AFRC-JFRC 20004 Joint International Combustion Symposium, Environmental Control of Combustion Processes: Innovative Technology for the 21st Century. (Oct. 10-13, 2004; Maui, Hawaii). http://www.nrcan.gc.ca/es/etb/cetc/ifc/id12_e.html
For example, during the 1990s, research conducted as part of the Petroleum Environmental Research Forum's project 92-19 "The Origin and Fate of Toxic Combustion By-Products in Refinery Heaters" showed that even when burning laboratory grade methane "pure as the drifted snow" traces of higher molecular weight compounds not originally present in the fuel are found in the flue gas (e.g., ethylene, propylene, butadiene, formaldehyde, benzene, benzo(a)pyrene and other hydrocarbons in the gas phase up through coronene).
Seebold, et al. also report that, "the external combustion of hydrocarbon gas mixtures by any means, including flaring, literally manufactures and subsequently emits to the atmosphere traces of all possible molecular combinations of the elemental constituents present either in the fuel or in the air including the ozone precursor highly reactive volatile organic compounds (HRVOCs) and the carcinogenic hazardous air pollutants (HAPs).
10. Leahey, Douglas M., Preston, Katherine and Strosher, Mel. 2001. Theoretical and Observational Assessments of Flare Efficiencies," Journal of the Air & Waste Management Association. Volume 51. p.1614. http://www.awma.org/journal/pdfs/2001/12/Leahey.pdf

Speciated data for combustion products observed downwind of the sweet gas flare using solvent extraction methods.

Product	Volume (mg/m3)	Product	Volume (mg/m3)
Nonane	0.41	9h-fluorene, 3-methyl-	3.05
Benzaldehyde (acn)(dot)	0.53	Phenanthrene	10.01
Benzene, 1-ethyl-2-methyl-	0.13	Benzo(c)cinnoline	2.06
1h-indene, 2,3-dihydro-	0.34	Anthracene	42.11
Decane	1.72	1h-indene, 1-(phenylmethylene)-	1.94
Benzene, 1-ethynyl-4-methyl-	9.83	9h-fluorene, 9-ethylidene-	0.89
Benzene, 1,3-diethenyl-	1.27	1h-phenalen-1-one	1.86
1h-indene, 1-methylene-	0.28	4h-cyclopenta[def]phenanthrene	3.50
Azulene	21.20	Naphthalene, 2-phenyl-	1.98
Benzene, (1-methyl-2-cyclopropen-1-yl)-	11.47	Naphthalene, 1-phenyl-	1.82
1h-indene, 1-methyl-	1.66	9,10-anthracenedione	0.94
Naphthalene (can)(dot)	99.39	5h-dibenzo[a,d]cycloheptene, 5-methylene-	0.75
Benzaldehyde, o-methyloxime	0.27	Naphthalene, 1,8-di-1-propynyl-	1.14
1-h-inden-1-one, 2,3-dihydro-	0.74	Fluoranthene 51.35 Benzene, 1,1'-(1,3-butadiyne-1,4-diyl)bis-	2.07

Naphthalene, 2-methyl-	9.25	Pyrene	32.37
Naphthalene, 1-methyl-	6.18	11h-benzo[a]fluorene	2.25
1h-indene, 1-ethylidene-	1.22	Pyrene, 4-methyl-	9.13
1,1'-biphenyl	58.70	Pyrene, 1-methyl-	8.38
Naphthalene, 2-ethyl-	1.87	Benzo[ghi]fluoranthene	10.16
Biphenylene	42.81	Cyclopenta[cd]pyrene	29.77
Naphthalene, 2-ethenyl-	7.32	Benz[a]anthracene	17.33
Acenaphthylene	7.15	Chrysene	2.12
Acenaphthene	2.93	Benzene, 1,2-diphenoxy-	1.94
Dibenzofuran	0.88	Methanone, (6-methyl-1,3-benzodioxol-5-yl)phenyl-	0.95
1,1'-biphenyl, 3-methyl-	0.31	Benzo[e]pyrene	0.71
1h-phenalene	21.01	Benzo[a]pyrene	1.03
9h-fluorene	41.09	Perylene	0.62
9h-fluorene, 9-methyl-	1.07	Indeno[1,2,3-cd]pyrene	0.15
Benzaldehyde, 4,6-dihydroxy-2,3-dimethyl	1.16	Benzo[ghi]perylene	0.26
9h-fluorene, 9-methylene-	1.07	Dibenzo[def,mno]chrysene	0.15
		Coronene	0.08

11. U.S. Environmental Protection Agency. 2000. Office of Air Quality Planning and Standards. "Industrial Flares," AP-42 Fifth Edition. Vol. 1: Stationary Point and Area Sources. p. 13.5-3.
Tendency to smoke or make soot is influenced by fuel characteristics and by amount and distribution of oxygen in the combustion zone. All hydrocarbons above methane tend to soot. Soot from industrial flares is eliminated by adding steam or air.
Soot emissions factors developed by EPA for industrial flares are: non-smoking flares, 0 micrograms per liter (µg/L); lightly smoking flares, 40 µg/L; average smoking flares, 177 µg/L; and heavily smoking flares, 274 µg/L.
12. K.D. Siegel. 1980l. Degree of Conversion of Flare Gas in Refinery High Flares. Dissertation. University of Karlsruhe, Germany. Cited in: USEPA Office of Air Quality Planning and Standards. 2000. "Industrial Flares,"AP-42 Fifth Edition. Volume 1: Stationary Point and Area Sources. p.13.5-5.
Even waste gas that does not contain nitrogen compounds form NO. It is formed either by fixation of atmospheric nitrogen with oxygen, or by the reaction between hydrocarbon radicals and atmospheric N by way of intermediate states, HCN, CN and OCN.
13. Health and Environmental Effects of Chemicals Released During Venting and Flaring.

	VOCs	SO2	NOx	CO	PAHs	H2S	HAPs	SMOKE/ SOOT
Contributes to particulate pollution that can cause respiratory illness, aggravation of heart conditions and asthma, permanent lung damage and premature death.	FLARING	FLARING	FLARING					FLARING
Aggravates respiratory conditions						VENTING		
								FLARING

	VOCs	SO2	NOx	CO	PAHs	H2S	HAPs	SMOKE/SOOT
Can cause health problems such as cancer	VENTING						VENTING	
	FLARING				FLARING		FLARING	
Can cause reproductive, neurological, developmental, respiratory, immune system, and other health problems.							VENTING	
							FLARING	
Reacts with other chemicals leading to ground-level ozone and smog, which can trigger respiratory problems	VENTING							
	FLARING		FLARING					
Reacts with common organic chemicals forming toxins that may cause bio-mutations								
			FLARING					
Affects cardiovascular system and can cause problems within the central nervous system						VENTING		
Causes haze that can migrate to sensitive areas such as National Parks	VENTING							
	FLARING	FLARING	FLARING	FLARING				FLARING
Contributes to global warming	VENTING							

Adapted from: EPA Office of Inspector General. 2004. EPA Needs to Improve Tracking of National Petroleum Refinery Program Progress and Impacts. Appendix D.

14. Russell, J. and Pollack, A. (ENVIRON International). 2005. Final Project Report: Oil And Gas Emission Inventories For The Western States. Report prepared for the Western Governors' Association. Appendix A, Wyoming Emission Factor Documentation. p. A-2.
http://www.wrapair.org/forums/ssjf/documents/eictts/OilGas/WRAP_Oil&Gas_Final_Report.122805.pdf

15. Strosher, M. 1996. Investigations of Flare Gas Emissions in Alberta. Alberta Research Council, November 1996. p. 28.
Strosher measured concentrations of hydrocarbon compounds emitted from sweet and sour solution gas flares in Alberta, and then predicted ground-level concentrations of HAPs at various locations around the well location. Predicted values of some polycyclic aromatic hydrocarbons in the vicinity of sweet and sour gas flares were comparable to concentrations found in large industrial cities, while predicted values of hazardous VOCs released during flaring were below ambient air quality standards.

Mitigation Option: Co-location/Centralization for New Sources

I. Description of the mitigation option

This mitigation option would involve co-locating and/or centralizing new oil/gas field facilities, including roads, well pads, utilities, pipelines, compressors, power sources and fluid storage tanks, wherever possible, to reduce surface impacts, fugitive dust, engine emissions and gas field traffic.

In general, co-location and/or centralization of new facilities would result in overall reductions in surface disturbance, vehicular traffic, and number of facilities. Potential benefits from this strategy include fugitive dust reduction (due to decreased traffic and less overall new surface disturbance), vehicle emission reductions, reduced road maintenance, safer roads as a result of decreased traffic, and oil/gas field engine emission reductions. The potential for reduced engine emissions is due in part to lowering cumulative horsepower requirements by using larger, more efficient engines, and in part to groups of smaller engines with relatively high emission rates per hp/hr being replaced by fewer, larger engines with relatively low emission rates per hp/hr. Implementation costs for this mitigation option would fall exclusively on the energy companies, but such costs could be partially offset by the economic benefits of having fewer facilities to construct, maintain and ultimately reclaim.

Tradeoffs include increased impacts at co-located/centralized sites. Co-locating well bores on a single pad results in larger pad sizes that may not fit well with pre-existing conditions. Centralizing facilities would increase vehicle emissions locally and potentially produce local air quality, noise, visual and traffic safety issues. Additionally, aggregating produced water in one location increases the potential for a catastrophic release.

II. Description of how to implement

A. This mitigation option should be implemented on a voluntary basis, with the approach emphasized by the appropriate regulatory agency during the planning and permitting processes for oil/gas field facilities and utility corridors (pipelines, power lines, etc.). Consideration should be given to economic and environmental impacts, as well as current and future land management activities. Ideally, oil/gas field operators and regulatory agencies would coordinate on a regular basis to identify development plans that minimize new construction and maximize efficiencies. Cooperation between operators in the same development area would make this option even more effective, but multiple economic and regulatory constraints exist that make such coordination difficult.

B. State and Federal lands and minerals management agencies would be able to emphasize this approach at various stages of the planning and permitting process. In addition, State and Federal air regulatory agencies could emphasize this approach if multiple air quality permit applications are submitted concurrently for the same general area.

III. Feasibility of the option

A. Technical: The technology exists today to implement this mitigation option. This option is best suited for areas of known or high potential for economic oil/gas field production. This option can be implemented most effectively when planning for oil/gas field- or lease-wide development activities, such as in-fill drilling and plans of development for multiple wells.

B. Environmental: Co-location and/or centralization of new facilities would generally have numerous environmental benefits.

C. Economic: Economic feasibility of this option will vary on a project-level basis. Higher initial costs may be offset by overall cost reductions due to fewer facilities to construct, operate and reclaim. Additional cost savings may result because co-located/centralized facilities can be more efficient than dispersed facilities.

IV. Background data and assumptions used
This option is best suited for areas with existing or high potential for economic gas/oil field production.

V. Any uncertainty associated with the option
Low. While implementation of this option may cause greater noise, emission, and visual impacts at fewer, co-located/centralized locations, the overall effect would be a reduction in oil/gas field environmental impacts.

VI. Level of agreement within the work group for this mitigation option Unknown at this time

VII. Cross-over issues to the other source groups
Road-related impacts are an element of this mitigation option being looked at by the Other Sources Workgroup. Two other mitigation strategies (Optimization/Centralization and Reduced Truck Traffic by Centralizing Produced Water Storage Facilities) look at the compression and produced water facets of this mitigation option in greater detail and are presented in the Oil and Gas section of this Task Force Report. Assistance from the Cumulative Effects work group to quantify potential dust, vehicle traffic and overall emission reductions resulting from co-location and/or centralization would be helpful.

VIII. References

http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices.html

http://www.westgov.org/wga/initiatives/coalbed/

http://bogc.dnrc.state.mt.us/website/mtcbm/webmapper_cbm_info_res.htm

Mitigation Option: Control Glycol Pump Rates

I. Description of the mitigation option
Most dehydration systems use triethylene glycol (TEG) as the absorbent fluid to remove water from natural gas. As TEG absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). As TEG is regenerated through heating in a reboiler, absorbed methane, VOCs, and HAPs are vented to the atmosphere with the water, wasting gas and money. The amount of methane absorbed, and used as assist gas for Kimray type pumps, and vented is directly of the TEG Dehydrator, but continue to circulate TEG at rates two or three times higher than necessary, resulting in little improvement in gas moisture quality but much higher methane emissions and fuel use. Reducing TEG circulation rates reduce methane emissions at negligible cost.

Economic burdens are minimal since this practice simply requires the pump rate to be manually adjusted.

II. Description of how to implement
A. Mandatory or voluntary: The implementation of lower TEG circulation rates should be "voluntary" since the measure would enhance recovery of natural gas and reduce emissions. Companies should be receptive to voluntarily implement this measure.
B. Indicate the most appropriate agency(ies) to implement**:** The state Air Quality Divisions should communicate this information.

III. Feasibility of the option
A. Technical: Controlling TEG circulation rates are technically feasible since it can be achieved by manually setting the pump rate.
B. Environmental: The environmental benefits of reduced VOC pollution are well documented. The reduction of methane, a greenhouse gas, can also be documented. Quantification of emission reductions can be achieved through the use of the GLYCALC model.
Due to the low field pressures in the San Juan basin area, most field dehydrators have been removed and dehydration is done at central facilities rather than dispersed locations. Due to this, this option will have very limited applicability and emission reductions associated with it.
C. Economic: The benefits can be quantified by the amount of methane and VOC that is not emitted to the atmosphere and rather sold as product.

IV. Background data and assumptions used
A. Gas production fields experience declining production as pressure is drawn-off the reservoir. Wellhead glycol dehydrators and their TEG circulation rates are designed for the initial, highest production rate, and therefore, become over-sized as the well matures. It is common that the TEG circulation rate is much higher than necessary to meet the sales gas specification for moisture content.
B. The methane emissions from a glycol dehydrator are directly proportional to the amount of TEG circulated through the system. The higher the circulation rate, the more methane, is vented from the regenerator. Over-circulation results in more methane emissions without significant and necessary reduction in gas moisture content.
C. Operators can reduce the TEG circulation rate and subsequently reduce the methane emissions rate, without affecting dehydration performance or adding any additional cost.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option
Although a general discussion of this option has not occurred between the working group members, it is doubtful a disagreement about controlling TEG circulation rates would occur.

Source of Information: **"**Optimize Glycol Circulation and Install of Flash Tank Separators in Dehydrators", U.S. EPA Natural Gas Star Program.

Mitigation Option: Combustors for Still Vents

I. Description of the mitigation option

Most dehydration systems use triethylene glycol (TEG) as the absorbent fluid to remove water from natural gas. As TEG absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). The TEG is then distilled to strip water and consequently VOC from the TEG. Vapors and/or liquids in the still vent are typically greater than 90% volume water, with the balance being hydrocarbons along with small quantities of carbon dioxide and nitrogen. The still vent column is typically released to the atmosphere that includes emissions of hydrocarbons. It is important to note that gas composition is an important consideration in determining the need to install flares. Some natural gas, such as coalbed methane gas contains little, if any VOC component, and would not result in VOC emissions.

In order to reduce these emissions, combustion devices can be installed to combust hydrocarbon emissions, including VOCs, instead of venting them to the atmosphere. The combustion technology typically consists of an enclosed "flare/burner." It does require a condenser and separator upstream of the combustion device to avoid liquid hydrocarbons routed to the combustion device.

II. Description of how to implement

A. Mandatory or voluntary: The requirement for control of emissions from glycol dehydrators is included in the EPA's area source *Onshore Natural Gas Processing* MACT rules that have been proposed/promulgated. After careful analysis, EPA set emission and throughput based criteria to trigger these control requirements. Any control at lower emission or throughput rates should be voluntary.

B. Indicate the most appropriate agency(ies) to implement**:** The state Air Quality Divisions should develop the regulatory program to administer this program.

III. Feasibility of the option

A. Technical: Installing condensers and combustion devices to control emissions from dehydrator still vents is technically feasible since it is already being applied in various locations where controls of these emissions have been mandated.

B. Environmental: The environmental benefits of reduced VOC emissions are well documented. The reduction of methane, a greenhouse gas, can also be documented. Actual benefits are dependent on the amount and composition of the gas being dehydrated and are highly variable. Little benefit is expected for the San Juan basin due to the lack of field dehydration.

C. Economic: Costs are for a typical condenser and smokeless combustion chamber large enough to service a dehydrator in Wyoming are about $35,000 installed. There are no revenues from the gas as it is destroyed through combustion, and there is a fuel cost of about $1,800 per year for each pilot (at $3 per Mcf of gas).

IV. Background data and assumptions used Wyoming oil and gas presumptive BACT guidance.

V. Any uncertainty associated with the option Low where applicable.

VI. Level of agreement within the work group for this mitigation option

Although a general discussion of this option has not occurred between the working group members, it is unknown about the degree of acceptance regarding the use of combustors for still vents.

Source of Information: "Install Flares"**,** PRO Fact Sheet No. 905, U.S. EPA Natural Gas Star Program. Gas Research Institute, Control Device Monitoring of Glycol Dehydrators; Condenser Efficiency Measurements and Modeling, 1997.

EXPLORATION & PRODUCTION: WELLS

Mitigation Option: Installation and/or Optimization of a Plunger Lift System

I. Description of the mitigation option

Overview
In mature gas wells, the accumulation of fluids in the well-bore can impede and sometimes halt gas production. Fluids are removed and gas flow maintained by removing accumulated fluids through the use of artificial lift (such as a beam pump) or enhanced fluid lift treatments or techniques, such as plunger lifts, velocity strings, swabbing, soap injection, or venting the well to atmospheric pressure (referred to as "blowing down" the well). Fluid removal operations, particularly well blow-downs, may result in substantial methane and associated VOC emissions to the atmosphere.

Installing a plunger lift system can be a cost-effective alternative for removing liquids on wells where the well-bore configuration, pressure profiles, and production characteristics enable its application. Plunger lift systems have the additional benefit of potentially increasing production, as well as significantly reducing methane and associated VOC emissions associated with blow-down operations. A plunger lift uses gas pressure buildup in a well to lift a column of accumulated fluid out of the well. The plunger lift system helps to maintain gas production and may reduce the need for other remedial operations.

Air Quality and Environmental Benefits

The installation of a plunger lift system serves as an interim well-bore deliquification methodology for the period between natural flowing lift and full artificial lift and can yield environmental and production benefits while reducing well blow-downs and their associated emissions. The extent and nature of these benefits depend on the individual well characteristics and the method of plunger lift control and operation.

New automation systems and control capabilities can improve plunger lift system optimization, monitoring, and control. For example, technologies such as programmable logic controllers and remote transmitter units can allow operators to control plunger lift systems thorough control algorithms or remotely, without regular field visits. These systems can offer enhanced plunger lift operation and effectiveness versus older plunger control systems.

By reducing the need for well-bore blow-down, plunger lift systems can lower emissions. Reducing repetitive remedial treatments and well work-over may also reduce methane and associated emissions. Natural Gas STAR partners have reported annual gas savings averaging 600 Mcf per well by avoiding blow-down and an average of 30 Mcf per year by eliminating or reducing well work-overs.

Economics
Lower capital and operational cost versus installing full artificial lift equipment (such as a beam pump). The costs of installing and maintaining a plunger lift are generally lower than the cost to install and maintain artificial lift equipment.

Lower well maintenance and fewer remedial treatments. Overall well maintenance costs are reduced because periodic remedial treatments such as swabbing or well blow-downs are reduced or no longer needed with plunger lift systems.

More effective well-bore deliquification and continuous production may improve gas production rates and increase efficiency. With proper optimization and control, plunger lift systems can also conserve the well's lifting energy and increase gas production. Regular fluid removal allows the well to produce gas continuously and helps prevent fluid loading that periodically halts gas production or “kills” the well. Often, the continuous removal of fluids results in daily gas production rates that are higher than the production rates prior to the plunger lift installation.

Reduced paraffin and scale buildup. In wells where paraffin or scale buildup is a problem, the mechanical action of the plunger running up and down the tubing may prevent particulate buildup inside the tubing. Thus, the need for chemical or swabbing treatments may be reduced or eliminated. Many different types of plungers are manufactured with “wobble-washers” to improve their “scraping” performance.

Other economic benefits. In calculating the economic benefits of plunger lifts, the savings from avoided emissions and enhanced production are only two factors to consider in the analysis. Additional savings may result from lower operational and well work costs.

Tradeoffs
Plunger lift systems do fail and can require additional maintenance versus blowing wells down. If return velocity is not controlled they may also “launch” through the plunger receiver and cause wellhead failure. Also, dependent on the control systems, they may require regular operator intervention.

Burdens
Installation of plunger lift systems can involve substantial costs particularly if changes to the well-bore tubulars are required. If adequate control systems and a means to power them are not available on a particular well, their installation will require additional expenditures.

II. Description of how to implement
A. Mandatory or voluntary: This option should be voluntary given the restrictions on applicability posed by well-bore configuration, pressure and build-up profile, and production characteristics. Each well must be evaluated for feasibility of plunger lift systems. A large number of wells in the Four Corners area already have artificial lift systems or other enhanced deliquification techniques already installed. Requiring all wells in the basin to replace other means of enhanced or artificial lift would be logistically and operationally unreasonable. A large percentage of the producing wells in the 4-corners area are already equipped with plunger lift systems. Most operators have an ongoing well evaluation program to determine the appropriate deliquification technology to apply to any particular well.
B. Indicate the most appropriate agency(ies) to implement**:** Non-applicable – voluntary implementation. However, workshops on plunger lift applicability, control, and operation may enhance implementation.

III. Feasibility of the option
A. Technical: The technical considerations necessary for plunger lift systems are well known and plunger lift systems are feasible where the well characteristics enable application. For very low pressure/flow environments, such as portions of the San Juan Basin, operation of plunger lifts may require periodic venting (blow-down) of well-bores to the atmosphere to generate enough differential energy to lift the plunger and associated fluids. Advanced control systems can significantly reduce the need for this type of blow-down but require robust automation capabilities.
B. Environmental: There are no known environmental issues with plunger lift implementation and they typically reduce emissions.
C. Economic: the economics of applying plunger lift technology to a particular well must be evaluated on a well-by-well basis. For wells where they are applicable, plunger lift systems are generally economic.

IV. Background data and assumptions used N/A

V. Any uncertainty associated with the option

Assuming a well-by-well evaluation of applicability the uncertainty associated with plunger lift implementation should be low. Due to the large number of wells already equipped with plunger lift or other enhanced or artificial lift systems the scope of available implementation may be limited.

VI. Level of agreement within the work group for this mitigation option

Still being evaluated, but based upon information to date it should be high.

Mitigation Option: Implementation of Reduced Emission Completions (Green Completions)

I. Description of the mitigation option

The "green completions" control method reduces methane losses during gas well completions. During well completions it is necessary to clean out the well bore and the surrounding formation perforations. This is done both after new well completions and after well workovers. Operators produce the well to an open pit or tanks to collect sand, cuttings and reservoir fluids for disposal. Normal practice during this process is to vent or flare the natural gas produced. Venting may lead to dangerous gas buildup, so flaring is preferred where there is no fire hazard or nuisance issue (concerns about smoke, light, noise, etc.). Green completions recover the natural gas and condensate produced during well completions or workovers. This is accomplished using portable equipment to process the gas and condensate so it is suitable for sale. The additional equipment may include more tanks, special gas-liquid-sand separator traps, and portable gas dehydration. The recovered gas is directed through permanent dehydrators and meters to sales lines, reducing venting and flaring. "Green completion" techniques are only applicable where the reservoir pressure and flow is sufficient to clean-up a well bore after completion and still have sufficient pressure to enter the collection system/pipeline. With the depleted status of the conventional San Juan basin reservoirs and the characteristics of coal bed methane reservoirs; this is not an available option for the SJ basin area.

II. Description of how to implement

A. Mandatory or voluntary

This process can be mandatory or voluntary.

B. Indicate the most appropriate agency(ies) to implement

For the 4 Corners area, State regulatory agencies could require green completions through regulation or policy. For example, in the Pinedale, WY area the State of Wyoming, BLM, and operators have agreed to minimize flaring operations through use of green completions. FLMs could require this process through stipulations or conditions of approval in leases and applications for permits to drill.

III. Feasibility of the option

A. Technical

The green completion process can apply to the drilling of all natural gas wells, however, a sales line connection and sales agreements need to be arranged before the well drilling is completed. There are operational, access and other considerations that make this a case determination.

Differing opinion: This technique is not feasible in the SJ basin – see above.

The green completion process has been reviewed by EPA and is listed under "Recommended Technologies and Practices" on EPA's Natural Gas Star Program web site: http://www.epa.gov/gasstar/techprac.htm **Differing opinion:** This technology may not be applicable in all cases, and needs careful consideration. Different formations typically require different completion techniques that this technology may not be suited to handle. E.g. many operators use compressed air to fracture coal wells. Air mixed with natural gas cannot be shipped to a pipeline due to the high potential for spontaneous combustion under typical pipeline temperatures and pressures. Additionally, oxygen contamination of natural gas causes additional corrosion risks to gathering lines. Separation of air from natural gas is presently not feasible or part of the process equipment used in "green completions."

B. Environmental

Nationally EPA has estimated that 25.2 billion cubic foot (Bcf) of natural gas can be recovered annually using Green Completions - 25,000 million cubic foot (MMcf) from high pressure wells, 181 MMcf from low pressure wells, and 27 MMcf from workovers. This reduces emissions of methane (a greenhouse gas), condensates (hazardous air pollutants), and nitrogen oxides (precursor to ozone formation and visibility degradation) formed when gas is flared. An EPA Gas Star Partner reported an estimated methane emissions reduction, as the total recovered from 63 wells, of 7.4 MMcf per year, which is 70 percent of the gas formerly vented to the atmosphere.

C. Economic

A methane savings of 7 MMcf per year based on completing 60 wells per year at the average recovery reported by an EPA Gas Star partner. The partner also reported recovering a total of 156 barrels of condensate from the 63 wells, an average of 2.5 barrels per well.

The capital costs include additional portable separators, sand traps, and tanks at a cost reported by the partner of $180,000. This equipment would be moved from well-to-well, so amortizing the cost over 10 years and doing 60 wells per year, the annual capital charges would be under $10,000. Incremental operating costs are assumed to be over $1,000 per year. At a natural gas price of $3 per Mcf and condensate price of $19 per barrel, green completions will pay back the costs in about 1 year. This information is for green completions in the Green River Basin area of Wyoming and is for much higher rate wells with much higher pressures and energy than the SJ basin wells.

IV. Background data and assumptions used

Information on Green Completions comes from EPA's Natural Gas Star Program web site: http://www.epa.gov/gasstar/techprac.htm

V. Any uncertainty associated with the option

Low, if the well is part of an in-fill and a sales line connection is available. Other situations may not be suitable for green completions.

Differing opinion: Very High – this is not a viable option for the SJ basin area – see above.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None.

Mitigation Option: Convert High-Bleed to Low or No Bleed Gas Pneumatic Controls

I. Description of the mitigation option

This option would encourage oil and gas producers and pipeline owners and operators to replace or retrofit high-bleed natural gas pneumatic controls. This option should be considered when replacement of pneumatic controls with compressed instrument air systems is not practical or feasible (e.g. no electric power supply). It would enhance EPA's current efforts in the Natural Gas Star Program and make them specific to the San Juan Basin. This would result in a significant reduction in methane emissions as well as achieve cost savings for the companies.

Pneumatic instrument systems powered by high-pressure natural gas are often used across the natural gas and petroleum industries for process control. Typical process control applications include pressure, temperature, liquid level, and flow rate regulation. As part of normal operation, natural gas powered pneumatic devices release or bleeds gas to the atmosphere and, consequently, are a leading source of methane emissions from the natural gas industry. High–bleed pneumatic devices are defined as those with bleed rates of 6 standard cubic feet per hour (scfh) or 50 thousand cubic feet (Mcf) per year. An EPA study in 2003 reported the constant bleed of natural gas from these controllers was collectively one of the largest sources of methane emissions in the natural gas industry, estimated at approximately 24 billion cubic feet (Bcf) per year in the production sector, 16 Bcf from processing and 14 Bcf per year in the transmission sector. Pneumatic control systems emit methane from tube joints, controls, and any number of points within the distribution tubing network.

Companies have found that the payback period can be less than a year for most retrofits from high-bleed to low-bleed pneumatic controllers. Recent experience indicates that up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment or retrofitted. If electric power is available, conversion from natural gas-powered pneumatic control systems to compressed instrument air systems will result in greater methane emissions reductions. However, the investment payback period will likely be longer, and may not be cost effective in some cases.

In compressed instrument air systems, atmospheric air is compressed, stored in a volume tank, filtered and dried for instrument use. All other parts of a gas pneumatic system work the same way with air as they do with gas. Existing pneumatic gas supply piping, control instruments, and valve actuators of the gas pneumatic system can be reused in an instrument air system.
Reducing methane emissions from pneumatic devices by converting to instrument air systems can yield significant economic and environmental benefits for natural gas companies including:

- Financial Return From Reducing Gas Emission Losses. In many cases, the cost of converting high-bleed to low-bleed pneumatic controllers can be recovered in less than a year.
- Lower Methane Emissions

II. Description of how to implement

A. Mandatory or voluntary: This program would be voluntary. Due to the fact that almost all high-bleed pneumatics have been replaced by the industry, the economic returns from implementing low bleed systems should motivate producers to implement them. State and Federal agencies can assist by advertising the benefits, as is currently done by EPA's Natural Gas Star Program.
B. Currently most operators have already replaced all high bleed with low bleed systems.
C. Indicate the most appropriate agency(ies) to implement: EPA and the State environmental agencies would extend and enhance EPA's current efforts to make them specific to the San Juan Basin.

III. Feasibility of the option
A. Technical: These systems are off-the-shelf and proven.
B. Environmental: The environmental benefits of replacing high-bleed with low-bleed pneumatic controls, in terms of lower methane emissions, have been documented by EPA. Companies reporting to EPA have reduced emissions by 50-260 Mcf per year per controller.
C. Economic: EPA reports that replacing or retrofitting high-bleed units with low-bleed units have a payback of five to 21 months.

IV. Background data and assumptions used
See the website for EPA's Natural Gas Star Program: http://www.epa.gov/gasstar/index.htm

In particular, the lessons learned summaries for low-bleed pneumatics:
http://www.epa.gov/gasstar/pdf/lessons/ll_pneumatics.pdf

V. Any uncertainty associated with the option
Low. This is proven technology with proven benefits.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups
Cumulative effects should review oil and gas tasks and rank those most effective as priorities over those less effective or cost effective.

Mitigation Option: Utilizing Electric Chemical Pumps

I. Description of the mitigation option
This option involves replacing existing gas drive pumps with solar powered, electric-driven chemical pumps. The air quality benefits would be to minimize methane and VOC emissions to the atmosphere (Methane, VOC).

Economic burdens are significant but not insurmountable if the cost recovery factor from reduced fuel usage over the anticipated life of the unit shows a positive return on investment.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.

Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement
A. Mandatory or voluntary: The implementation of measures to install electric-driven, solar powered chemical pumps are envisioned as "voluntary" measures since the feasibility of installing insulation on new units or retrofitting existing units must be evaluated for a positive Net Present Value (NPV) or Return on Investment (ROI) in the Four Corners area. If the NPV or ROI meets a company's investment targets, then utilization of this technology should be encouraged as a best practice. There are no existing mandates by the respective Air Quality Control agencies to require electric drive pumps as BACT. Since the Four Corners area is not in ozone non-attainment and the cost economics will not always justify installation of insulation for economic benefit, a voluntary approach is recommended.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option
A. Technical: The purchase and installation of electrically driven chemical pumps is technically feasible. Currently some companies are installing these pumps on a trial basis to assure performance during the winter months.
B. Environmental: The environmental benefits of reduced Methane and VOC pollution are well documented.
C. Economic: The use of electric-driven, solar powered chemical pumps is economically feasible where the there is payback that meets the respective companies targets for investments (i.e., ROI or NPV). For existing older pumps exist on wells that have a future limited life, the economics may not justify the application of insulation.

IV. Background data and assumptions used
Most chemical pumps in the Four Corners area are utilized year round to achieve their objective.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option
There is general agreement among working group members that the use of electrical chemical pump technology in the Four Corners areas is economically unfeasible and a likely source for voluntary adoption if the economics show a sufficient NPV.

Mitigation Option: Solar Power Driven Wellsites and Tank Batteries

I. Description of the mitigation option

This option comprises a system of production equipment and controls powered by solar generated electricity (through Photovoltaic – PV - cells) at gas well production sites that are not served with grid power. In most cases solar power replaces pressurized fuel gas, which is usually vented to the atmosphere after use. The power supply consists of solar panels and batteries. The solar power is used for electric instruments, controllers, actuators for automatic valves and small additive (methanol) pumps. Optimization consists of selecting the best fit items of hardware, becoming familiar with the strengths and limitations of all of the individual items as well as the overall system and making modifications to improve performance.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory on all new wellsites with gas-assisted chemical injection pumps. Mandatory where economic at existing wellsites. Propose to define a standardized calculation to determine if it is economic. An example borrowed from the Alberta EUB – Energy & Utilities Board – Directive 60, agreed to by a multi-stakeholder group including the oil & gas industry, includes the following:

1) Before tax basis
2) Point to an agreed upon specific gas forecast report
3) Must have remaining reserves calculation and production forecast (NPV calculated over life of well/production)
4) Only incremental capital costs related to the solar PV skid system may be included
5) Long term inflation based on CPI forecast
6) Discount rate = prime lending rate + 3%
7) Only revenue minus net royalties from incremental gas conservation only to be included
8) Economic if NPV before tax > $0

B. Indicate the most appropriate agency(ies) to implement**:** The States on State land or Federal/Tribe on Indian country.

III. Feasibility of the option

A. Technical: In the past two years an operator in Alberta has installed over 40 of these systems. Supported by operations managers, instrumentation personnel carried out trials with solar systems and electrical equipment to arrive at a "best fit" arrangement. In summer 2006, this operator carried out a study with outside specialist consultants in energy consumption and emissions monitoring to evaluate the performance of the system. The results of the study were very positive, resulting in this operator making their solar PV system the company standard for gas well production. The primary reasons for this are to reduce fuel consumption in producing operations, increase sales gas revenues and reduce vent gas emissions. There are also operators in the US Rocky Mountain area using solar PV systems in comparable ways.

B. Environmental: Reduced VOC emissions and reduced methane emissions (with a global warming potential ~23 times greater than CO2). Quantity of reduction would be dependent on number and bleed rate of pneumatic controllers, and size and supply gas use rate of pneumatic pump equipment, being replaced with electrically-powered devices.

C. Economic: Reduced fuel gas consumption so increased gas conservation and saleable product. These solar PV systems also minimize the requirement for expensive fuel gas regulators, shutdown devices and repair kits and stainless steel instrument tubing and fittings.

IV. Background data and assumptions used

See the presentation, "BP Canada Energy Company Innovative Methods for Reducing Greenhouse Gas - Low Emissions Wellsite" by Milos Krnjaja, BP Canada made at the "Energy Management Workshop for Upstream and Midstream Operations: Increasing Revenue through Process Optimization & Methane Emissions Reduction" in Calgary, Alberta Canada on 15-17 January 2007.
(http://www.methanetomarkets.org/events/2006/oil-gas/docs/15jan07-bp_canada_energy_company.pdf)

See the presentation, "Using Solar to Reduce Fugitive Gas Emissions" by Stuart Torr, Komex International made at the 2005 Energy Conservation and Air Emissions Technology Forum Wednesday, in Calgary, Alberta Canada on 19 October 2005.
(http://www.ptac.org/eet/dl/eetf0501p12.pdf)

See Database of State Incentives for Renewables and Efficiency (DSIRE) for a fast and convenient method to access comprehensive information on available state, local, utility, and federal **financial incentives** that promote renewable energy and energy efficiency.
(http://www.dsireusa.org/)

See Alberta Energy & Utilities Board – Directive 60 – Upstream Petroleum Industry Flaring, Incinerating, and Venting.
(http://www.eub.ca/docs/documents/directives/Directive060.pdf)

See Ber-Mac Electrical and Instrumentation for an example of a supplier of solar PV systems for instrumentation use. They have been in business since 1980 supplying electrical power and instrumentation equipment and services, both domestically and to international markets, supplying the needs of oil and gas companies all over the world. Their "Green Machine" is an environmentally-friendly, solar-powered operating system for new and existing wellsites.
(http://www.ber-mac.com/greenmachine.htm)

V. Any uncertainty associated with the option Low – a fair amount of industry experience and vendor capacity to-date.

VI. Level of agreement within the work group for this mitigation option

General agreement within working group members that this is viable.

EXPLORATION & PRODUCTION: PNEUMATICS / CONTROLLERS / FUGITIVES

Mitigation Option: Optical Imaging to Detect Gas Leaks

I. Description of the mitigation option
This option would encourage oil and gas producers and pipelines to use optical imaging to detect methane and other gaseous leaks from equipment, processing plants, and pipelines.

Optical imaging refers to a class of technologies that use principles of infrared light and optics to create an image of chemical emission plumes. They offer more cost-effective use of resources than traditional hand-held emissions analyzers, can screen hundreds of components or miles of pipeline relatively quickly and allow quicker identification and repair of leaks. The remote sensing and instantaneous detection capabilities of optical imaging technologies allow an operator to scan areas containing tens to hundreds of potential leaks, thus eliminating the need to visit and manually measure all potential leak sites.

Gas imaging can be either active or passive. Active gas imaging is accomplished by illuminating a viewing area with laser light tuned to a wavelength that is absorbed by the target gas to be detected. As the viewing area is illuminated, a camera sensitive to light at the laser wavelength images it. If a plume of the target gas is present in the imaged scene, it absorbs the laser illumination and the gas appears in a video picture as a dark cloud. Because it relies on the detection of backscattered radiation from surfaces in the scene, the process is referred to as Backscatter Absorption Gas Imaging (BAGI).

Passive gas imaging is based on a complex relationship between emission, absorption, reflection, and scatter of electromagnetic radiation. VOCs in the vapor phase have unique spectral emission and absorption properties. By measuring these properties, the gas species can be uniquely identified. By tuning the instrument's spectral response to the unique spectral region of the VOC, the camera can make an image of a gas plume.

There is a variety of technologies available and in different stages of development for imaging hydrocarbon gases. Plume imaging technologies include BAGI and Hyperspectral Imaging systems. Remote detection sensing instruments include Open-path Fourier Transform Infrared (OP-FTIR), Differential Absorption Spectroscopy (DOAS), Light Detection and Ranging (LIDAR-DIAL), and Tunable Diode Laser Absorption Spectroscopy (TDLAS). These instruments can be hand held or shoulder mounted, van mounted, or operated from a helicopter or fixed wing aircraft, depending on the technology and the facility to be inspected.

As an example, the ANGEL service, which uses Differential Absorption Lidar (DIAL), can detect specific hydrocarbon gases with color video imaging from a fixed wing aircraft, quantify the plume concentration, encode GPS data on the image, and cover 1000 miles per day. This technology is most suited to a facility such as a pipeline or tank farm. For a gas processing plant, a hand held or shoulder mounted camera may be the technology of choice.

The benefits of using optical leak detection in an inspection and maintenance program include:

- Reductions in hydrocarbon gas emissions, both greenhouse gases and hazardous air pollutants;
- Improved safety; and
- Typical payback of less than one year in reduced methane product losses.

II. Description of how to implement
A. Mandatory or voluntary: This program would be a voluntary Best Management Practice. The economic returns from implementing optical leak detection should motivate producers to implement

them. State and Federal agencies can assist by advertising the benefits, as is currently done by EPA's Natural Gas Star Program.
B. Indicate the most appropriate agency(ies) to implement: EPA and the state environmental agencies would extend and enhance EPA's current efforts to make them specific to the San Juan Basin.

III. Feasibility of the option
A. Technical: Several of these systems are commercially available.
B. Environmental: The environmental benefits of using optical imaging to detect and repair leaks have been documented. Companies reporting to EPA have reduced emissions significantly. Individual company results can be found on the EPA Natural Gas Star Program web site referenced below.
C. Economic: EPA reports that optical leak detection surveys pay for themselves in less than a year.
Differing opinion: Must be evaluated for each operation, may not be economic or applicable for all.

IV. Background data and assumptions used
See the web site for EPA's Natural Gas Star Program: http://www.epa.gov/gasstar/index.htm

Individual companies' experience with optical imaging leak detection:

Dynergy: http://www.epa.gov/gasstar/pdf/ngstar_fall2005.pdf

Enbridge: http://www.epa.gov/gasstar/workshops/houston-oct2005/dodson.pdf

Also see the agendas from the 2003 – 2005 Gas STAR Program annual implementation workshops: http://www.epa.gov/gasstar/workshops/imp_workshops.htm

Information on the ANGEL-DIAL technology:
http://www.epa.gov/gasstar/workshops/kenai/itt_sstearns.pdf

http://www.epa.gov/gasstar/pdf/ngspartnerup_spring06.pdf

Texas Commission on Environmental Quality report that includes comparison of various imaging technologies: http://www.tceq.state.tx.us/implementation/air/terp/Prop_02R04.html

V. Any uncertainty associated with the option Low. This is proven technology with proven benefits.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None known.

Mitigation Option: Convert Gas Pneumatic Controls to Instrument Air

<u>I. Description of the mitigation option</u>

This option would encourage oil and gas producers and pipelines to convert pneumatic controls from natural gas to compressed instrument air systems. It would enhance EPA's current efforts in the Natural Gas Star Program and make them specific to the San Juan Basin. This would result in a significant reduction in methane emissions as well as achieve cost savings for the companies.

Pneumatic instrument systems powered by high-pressure natural gas are often used across the natural gas and petroleum industries for process control. Typical process control applications include pressure, temperature, liquid level, and flow rate regulation. As part of <u>normal</u> operation, natural gas powered pneumatic devices release or bleed gas to the atmosphere and, consequently, are a major source of methane emissions from the natural gas industry. The constant bleed of natural gas from these controllers is collectively one of the largest sources of methane emissions in the natural gas industry, estimated at approximately 24 billion cubic feet (Bcf) per year in the production sector, 16 Bcf from processing and 14 Bcf per year in the transmission sector. Pneumatic control systems emit methane from tube joints, controls, and any number of points within the distribution tubing network.

Companies can achieve significant cost savings and methane emission reductions by converting natural gas-powered pneumatic control systems to compressed instrument air systems. Instrument air systems substitute compressed air for the pressurized natural gas, eliminating methane emissions and providing additional safety benefits. Cost effective applications, however, are limited to those field sites with available electrical power.

In compressed instrument air systems, atmospheric air is compressed, stored in a volume tank, filtered and dried for instrument use. All other parts of a gas pneumatic system work the same way with air as they do with gas. Existing pneumatic gas supply piping, control instruments, and valve actuators of the gas pneumatic system can be reused in an instrument air system.
Reducing methane emissions from pneumatic devices by converting to instrument air systems can yield significant economic and environmental benefits for natural gas companies including:

- Financial Return from Reducing Gas Emission Losses. In many cases, the cost of converting to instrument air can be recovered in less than a year.
- Increased Life of Control Devices and Improved Operational Efficiency
- Avoided Use of Flammable Natural Gas. By eliminating the use of a flammable substance, operational safety is significantly increased.
- Lower Methane Emissions
-

The conversion of natural gas pneumatics to instrument air system is applicable to all natural gas facilities and plants where an electric power supply is available. For those sites that do not have electricity available, cost savings and methane emissions reductions can still be achieved by replacing high-bleed pneumatic devices with low bleed devices, retrofitting high-bleed devices, and improving maintenance practices. Experience has shown that these options often pay for themselves in less than a year.

<u>II. Description of how to implement</u>

A. <u>Mandatory or voluntary:</u> This program would be voluntary. The economic returns from implementing instrument air or low bleed systems should motivate producers to implement them. State and Federal agencies can assist by advertising the benefits, as is currently done by EPA's Natural Gas Star Program.
B. <u>Indicate the most appropriate agency(ies) to implement:</u> EPA and the state environmental agencies would extend and enhance EPA's current efforts to make them specific to the San Juan Basin.

III. Feasibility of the option

A. Technical: These systems are off-the-shelf and proven. Best utilized at larger facilities.
B. Environmental: The environmental benefits of replacing high-bleed pneumatic controls with instrument air, in terms of lower methane emissions, have been documented by EPA. Companies reporting to EPA have reduced emissions by an average of 20 Bcf per year per facility.
C. Economic: EPA reports that instrument air systems pay for themselves in less than a year. Replacing or retrofitting high-bleed units with low-bleed units have a payback of five months to one year.
Differing opinion: May not be economically justifiable or operationally sound for small facilities and well sites.

IV. Background data and assumptions used

See the web site for EPA's Natural Gas Star Program: http://www.epa.gov/gasstar/index.htm

In particular, the lessons learned summaries for instrument air:
http://www.epa.gov/gasstar/pdf/lessons/ll_instrument_air.pdf

And for low-bleed pneumatics:
http://www.epa.gov/gasstar/pdf/lessons/ll_pneumatics.pdf

V. Any uncertainty associated with the option Low: this is proven technology with proven benefits.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None known.

EXPLORATION & PRODUCTION: MIDSTREAM OPERATIONS

Mitigation Option: Application of NSPS and MACT Requirements for Existing Sources at Midstream Facilities

I. Description of the mitigation option

Overview

- This mitigation option would involve filling in the gaps where the NSPS and MACT fail to adequately regulate sources at midstream facilities. Filing in the gaps could include lifting exemptions on existing sources and lowering applicability thresholds. Specific examples include:
    - Subjecting existing stationary combustion turbines at midstream facilities to 40 CFR Part 63, Subpart YYYY;
    - Requiring existing 2 stroke lean burn and 4 stroke lean burn reciprocating internal combustion engines to meet 40 CFR Part 63, Subpart ZZZZ MACT standards at midstream facilities;
    - Requiring boilers, reboilers, or heaters with a design capacity of less than 10 mmBtu/hr to meet NSPS at 40 CFR Part 60, Subpart Dc at midstream facilities;
    - Requiring all midstream facilities to meet the requirements to 40 CFR Part 60, Subpart KKK; and
    - Requiring all amine sweetening units at midstream facilities to meet 40 CFR Part 60, Subpart LLL requirements.

  This option would involve case-by-case assessments of midstream facilities to determine whether additional pieces of equipment should be regulated under NSPS and MACT standards and to assess the feasibility of such regulation. The overall goal is to use NSPS and MACT standards as guides for further air pollution reductions at midstream facilities.

Air Quality/Environmental

- This mitigation option would lead to further reductions in hazardous air pollutants and criteria air pollutants by subjecting more units to regulation. By requiring more facilities and/or units to comply with NSPS and MACT, there may be an incentive to upgrade to cleaner equipment, which would provide additional air quality benefits.

Economics

- There would likely be additional costs associated with bringing previously unregulated facilities and/or units into compliance.
- The option may provide an incentive to replace older, less efficient equipment, which could lead to increased efficiency.
- There would be potential paybacks associated with methane recovery by complying with NSPS at Subpart KKK.

Tradeoffs

- None.

Burdens

- The burden would be on industry to bring facilities and/or units into compliance with the NSPS and MACT standard. Air quality impacts would be reduced, reducing burden on health and welfare. Regulatory agencies may have to revise rules to implement this mitigation options.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory. NSPS and MACT standards work best as mandatory requirements.
B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies, EPA.

III. Feasibility of the option

A. Technical: There will need to be case-by-case assessments, but this appears to be a technically feasible option.
B. Environmental: No environmental feasibility issues are known.
C. Economic: There may be economic concerns that should be addressed, but this option is not infeasible based on economics. The goal is clean air and that may take an investment.
D. Other: There will likely need to be rule changes to implement this option that may present feasibility issues.

IV. Background data and assumptions used

Background data and assumptions used came from review of EPA NSPS and MACT standards.

V. Any uncertainty associated with the option (Low, Medium, High):

Low uncertainty. The NSPS and MACT provide a solid basis for air pollution control options. However, further discussion and comments may reveal other means of using NSPS and MACT standards to keep air pollution in check.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups: None.

Mitigation Option: Specific Direction for How to Meet NSPS and MACT Standards: Directed Inspection and Maintenance

I. Description of the mitigation option

Overview

Meeting NSPS and MACT standards at Midstream facilities can often be achieved using a variety of methods, some of which may be better than others. For example, the EPA is proposing to allow the use of infrared cameras to meet Leak Detection and Repair (LDAR) requirements set forth in several NSPS and MACT standards. 70 Fed. Reg. pp. 17401-17409. The EPA has indicated that infrared cameras can provide better data than Reference Method 21.

This mitigation option provides specific direction on how to meet NSPS and MACT standards so that the best methods of compliance are met. Specifically, it requires operators to use approved infrared cameras to meet LDAR requirements set forth at 40 CFR Part 60, Subpart KKK and 40 CFR Part 63, Subpart HH and HHH.

It would also require operators to implement cost-effective options for reducing methane emissions, as outlined in Fernandez, et al. 2005, to meet applicable NSPS and MACT standards. These cost-effective options would vary depending on the equipment, but would include using vapor recovery units on tanks and dehydrators, using desiccant dehydrators rather than glycol dehydrators, replacing compressor rod packing after three years, replacing gas starters on compressor engines with air starters, and converting gas pneumatics at facilities to instrument air.

Air Quality/Environmental

- Meeting LDAR requirements using infrared cameras promises to better keep volatile organic compound and hazardous air pollutant emissions from leaking equipment in check. Implementing cost-effective options for reducing methane emissions will further reduce emissions. In both cases, methane emissions would be reduced, preventing further greenhouse gas emissions.

Economics

- This mitigation option will most likely yield a payback due to the recovery of methane. According to one case study, BP recovered $2.4 million in 2 months simply by recovering over 123 MMcf/yr of that was lost due to equipment leaks (see, http://www.epa.gov/gasstar/workshops/hobbs72706/dim.pdf).

Tradeoffs

- The use of some cost-effective methane control options may require the use of electricity, such as vapor recovery units, which may be generated through coal or natural gas burning. Potential increases in emissions from electricity generation could be prevented through the use of solar or other renewable energy sources.

Burdens

- The only burden would be the restriction of flexibility for the operators and the investment cost.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory. Although infrared cameras and methane control options can provide paybacks and are proven cost-effective, they are not widely used. Despite potential paybacks, current incentives do not appear to be strong enough to encourage their use. Mandatory requirements would provide that incentive.

B. Indicate the most appropriate agency(ies) to implement: State air quality agencies and EPA.

III. Feasibility of the option

A. Technical: Feasible, these technologies are already in use and are being implemented elsewhere.
B. Environmental: Vapor recovery units may require additional space at midstream facilities and could pose additional environmental impacts. This seems to present a limited environmental feasibility issue.
C. Economic: Given the paybacks from methane recovery, there are no economic feasibility issues.
D. Other: The EPA has not yet finalized its proposal to allow infrared cameras to be used solely to meet LDAR requirements in the NSPS and MACT.

IV. Background data and assumptions used

Background data was obtained from information on the EPA's Natural Gas Star Program website, www.epa.gov/gasstar, from the EPA's proposal to allow infrared cameras to be used to meet LDAR requirements at 70 Fed. Reg. 17401-17409, and from the Fernandez et al. 2005 paper, "Cost Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers," available online at http://www.epa.gov/outreach/gasstar/pdf/CaseStudy.pdf.

V. Any uncertainty associated with the option

Low uncertainty, especially with regards to the use of infrared cameras as effective tools to comply with NSPS and MACT LDAR requirements. Operators would still have to show that cost-effect methane control options would meet the applicable requirements of the NSPS and MACT.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups

Possibly the Cumulative Effects Group due to indirect emission increases from coal or natural gas burning plants that may accompany increased use of vapor recovery units or other methane control options requiring electricity.

OIL & GAS OVERARCHING

Mitigation Option: Lease and Permit Incentives for Improving Air Quality on Public Lands

I. Description of the mitigation option

This option would provide incentives in the form of exceptions or waivers from lease stipulations or permit conditions of approvals (COAs) for oil and gas drilling on public lands in exchange for a program of environmental mitigation activities that would reduce air emissions along with other types of environmental and ecological impacts.

Differing Opinion: The proposed activities that would reduce air emissions and surface disturbance in this section should become standard practices **but without** the proposed exchange for the exceptions or waivers from seasonal wildlife restrictions which would negatively impact public lands wildlife.

This option could provide incentives in the form of expedited permit processing for operating permits in exchange for a program of environmental mitigation activities that would require documented reductions in emissions from major and minor sources. This option is not intended to reduce protection for wildlife. Monitoring and adjustments in response to monitoring results would be used to assure that the package of mitigation activities and associated development does not adversely affect wildlife.

Differing Opinion: Additionally these incentives would not include the exception of waivers from lease stipulations or permit conditions of approval ("COAs") for oil and gas drilling on public lands.

Expedited operating permit issuance from the appropriate agency in exchange for additional emissions reductions offers incentives for both industry and the agencies

Industry Incentives include:

- The streamlining of operating permits.
- Direct and prompt cooperation with permit issuing agency.
- Obtaining an operating permit at an accelerated rate allows for an accelerated startup date, thus increased resource production (may be especially helpful for minor source operating permits).

Environmental Incentives include:

- The addition of emission control equipment such as a catalyst, Zero Emissions (a.k.a. Quantum Leap) Dehydrator, directional drilling, complying with emission limitations relating to hours of operation, lean burn engine, and/or implementing a program of environmental mitigation activities that would reduce air emissions.

This option would work well in the areas that smaller agencies, such as Tribes, oversee the operating permits. This option would be implemented by the applicable permitting agencies.

It would be modeled after the experience in the Pinedale Anticline and Jonah fields in Wyoming where producers face seasonal limitations on drilling due to concerns about wildlife impacts. As a result, drilling is prohibited for several months during the year, delaying development and increasing costs. Several producers have applied for and been granted permission to drill year round in exchange for efforts that mitigate environmental impacts. These efforts combine improved technologies and innovative practices that together greatly reduce adverse impacts. They include: directional drilling to reduce the number of drilling pads, and thus the amount of surface disturbance, by half or more; using natural gas-fired drilling rigs to reduce air emissions; transporting produced water by pipeline to eliminate truck trips;

using mat systems on drilling pads to reduce surface impact; partial remediation of drilling pads after the drilling phase; eliminating flares during well testing and completion to reduce air emissions and noise; centralized fracturing and production facilities; low impact road construction techniques; and produced water recycling. Producers and BLM will monitor wildlife impacts as part of the program. Year round drilling has the added benefits of reducing the duration of drilling operations by one third-to one-half, and increasing stability of the local community as workers move in with their families, rather than commuting seasonally.

Differing Opinion: This suggestion of modeling after the experience in Wyoming's Pinedale Anticline and Jonah fields fails to address the widespread and significant concerns that have been expressed regarding current and future impacts of oil and gas activity on wildlife in these fields and the wildlife population declines that have been documented through scientific studies. The Pinedale Anticline and Jonah field experience has not proven to be a model for wildlife, and recent proposals to increase drilling may even adversely impact a federally threatened species, the Bald Eagle, and further exacerbate problems for the sage grouse, a species which some believe should be listed as federally endangered because of recent population declines. Another report that helps put the Jonah field experience in perspective came in December 2006, stating that in places one well was being drilled per every five acres. Repeated concerns about the impact on wildlife in these areas of Wyoming have been expressed by numerous and diverse groups of people ranging from private citizens, outfitters, hunters, environmental organizations, scientists, to government agency personnel including personnel from Wyoming's Game and Fish Department. Drilling exceptions granted in crucial big game winter range around Pinedale early winter 2006/2007 were granted in the face of opposition by Wyoming's Game and Fish Department.

Differing Opinion Continued: Monitoring has also not been a model experience in this area. According to reports of a May 2006, internal assessment Pinedale, Wyoming, Bureau of Land Management field office, the office neglected its commitment to monitor and limit harm to wildlife and air quality from natural gas drilling in western Wyoming. A wildlife biologist who worked in that Pinedale office, Steve Belinda, is reported to have quit his job because he and other wildlife specialists were required to spend nearly all their time in the office processing drilling requests and were not able to go into the field to monitor the effect of the thousands of wells on wildlife.

This option would involve tradeoffs between seasonal restrictions, which would be relaxed, and a comprehensive wildlife and environmental impact plan which would use the kind of technologies and practices listed above. This plan would reduce impacts on wildlife, as well as on air quality, land and water resources, and on the local communities. Ecological and environmental monitoring would assess these impacts and allow for adjustments in the plans as activities proceed. All of these elements would be contained in agreements between the land management agencies and industry, with public input.

Differing Opinion: Exceptions or waivers from wildlife lease stipulations or permit conditions of approvals (COAs) for oil and gas drilling on public lands likely would increase negative impacts of oil and gas activities on wildlife in the Four Corners. At least in Northwest New Mexico and likely in the other Four Corners states, it is important to remember that the seasonal closures in the Bureau of Land Management Farmington Field Office management area exist only for parts of the year with their length dependent upon the animal species and the reason for the restriction such as elk calving or antelope fawning. The restrictions are in place to protect species during times of the year when they are especially vulnerable such as nesting for raptors; wintering for deer, elk, and Bald Eagles; and birthing and caring for young for antelope and elk. Provisions for waiving, excepting, or modifying the oil/gas lease stipulations already exist according to the Bureau of Land Management Farmington Field Office's 2003 Record of Decision for Farmington's Proposed RMP and Final Environmental Impact. These restrictions should remain in place to protect wildlife, especially with the current and anticipated intensity of drilling.

Differing Opinion Continued: An indication of the major potential for the impact of oil and gas activity on wildlife is found in the 2006 Annual Report of the Sublette Mule Deer Study conducted in the Pinedale Anticline Project Area. Study results that "suggest that mule deer abundance in the treatment area declined by 46 % in the first 4 years of gas development."

Differing Opinion Continued: In the summer, 2006, publication of the New Mexico Department of Game and Fish titled New Mexico Wildlife under the regional outlook for Northwest New Mexico, wildlife biologists are reported to be "concerned about the effects the severely dry spring had on fawn survival in the state's **already depressed deer herds**." [Bolding is this author's.]

Differing Opinion Continued: Removal of the wintering restrictions for mule deer could create problems in New Mexico and in both this state and Colorado where migratory populations are shared. Another word of caution is found in the Upper San Basin Biological Assessment in the Comprehensive Wildlife Conservation Strategy (New Mexico's wildlife action plan accepted by the US Fish and Wildlife Service in 2006), which places mule deer in its list of Species of Greatest Conservation Need in the Colorado Plateau Ecoregion. Under "Problems Affecting Habitats or Species" in Chapter 5 of this document is this statement: "Of particular concern are energy development…" along with invasive species and livestock grazing practices. The document states that "coal bed methane development in the San Juan Basin is currently a major land use…Depending on the scale, density, and arrangement of each well site in relation to other sites, habitat loss and fragmentation in the portions of this habitat type [Big Sagebrush Shrubland] subjected to energy development are extensive. At this high level of development, effects may not be successfully mitigated."

Differing Opinion Continued: Pronghorn antelope numbers were so low at the time the Farmington Field Office's Draft Pronghorn Antelope Habitat Management Plan was published in March 2004, that the populations were described as struggling to survive, a change from when this species was common in the 1950's and 1960's. The restriction of drilling and construction activity during antelope fawning period from May 1 through July 15 was proposed as one of the ways to bring the populations back to eventual self-sufficiency.

These actions reduce air emissions from drilling rigs, from trucks (both diesel emissions and road dust), and from flaring. There are also benefits from reduced surface impacts and improved water management, as well as improved community stability.

Differing Opinion Continued: The actions that are offered that will reduce air pollution appear to be important ways to address our air quality problem and should become required practice because of the serious air pollution problems in the San Juan Basin. They should not come at an expense to area wildlife, which is already negatively impacted by direct and functional habitat loss due to oil and gas activities, as delineated in the 2003 Bureau of Land Management Farmington Field Office Draft Resource Management Plan and Environmental Impact Statement.

This option would work well in areas of the Four Corners region where new oil and gas projects are being proposed and where those projects face access limitations from wildlife stipulations or COAs. In these cases, the land management agencies (principally the BLM and the Forest Service) would have the greatest opportunity to negotiate agreements for infrastructure and operational changes from project start, in exchange for relaxing the access restrictions, along with monitoring for wildlife impacts. Monitoring of the air quality impacts, including documentation of reductions over similar projects without mitigation, would be required.

In New Mexico, this option could be integrated with the New Mexico Oil and Gas Association's (NMOGA) Good Neighbor Initiative.

Differing Opinion: Year round drilling will not improve air quality. The current drilling seasons are in place to protect the wildlife in the area. The improved technologies and innovative practices described above should be standard industry requirements and not be used in trade for expanded drill seasons.

Differing Opinion: BLM should not entertain compromising one environmental value in exchange for protecting another when industry is legally mandated to protect both. Year round drilling will only add to the stress wildlife currently experience in an already highly fragmented habitat. Even more, in the San Juan Basin industry has demonstrated their reluctance to routinely employ directional drilling as a means to avoid further habitat fragmentation. Since directional drilling "all wells" would be the cornerstone of the proposed mitigation option it seems that this options would not be favorably received by industry.

II. Description of how to implement

A. Mandatory or voluntary: This program would be voluntary and would rely on the operators, the agencies, and any local communities obtaining benefits from the arrangements.

B. Indicate the most appropriate agency(ies) to implement: BLM and the Forest Service on Federal land. State and tribal land management agencies may implement this option on state and tribal lands.

III. Feasibility of the option

A. Technical: The technological approaches to reducing impacts are already being implemented in Wyoming and other locations.

Differing Opinion: Four Corners states should use the technological approaches without industry cost being a factor.

B. Environmental: The environmental benefits of the mitigation measures are currently being documented in Wyoming. Many of them seem apparent. The impact of year round drilling (or other permit-related incentives) on wildlife would have to be closely monitored.

C. Economic: Many environmental mitigation measures turn out to be economically attractive as well (e.g., natural gas drilling rigs can reduce fuel costs by two-thirds). Year-round drilling can shorten the project length by one-third to one-half, improving project economics. Producers would have to anticipate an economic benefit in order to enter into agreements.

IV. Background data and assumptions used

Web sites and presentations from operators and BLM on the experience with this kind of agreement in Wyoming. The NMOGA web site has information on their Good Neighbor Initiative.

See the following web sites:

BLM environmental assessment of year-round drilling in the Pinedale Anticline Field:
http://www.wy.blm.gov/nepa/pfodocs/questar/01ea.pdf
(See especially section 2.5 on Applicant-Committed Mitigation.)

Questar presentation on development in Pinedale:
http://www.wy.blm.gov/fluidminerals04/presentations/NFMC/028RonHogan.pdf\

BLM assessment of year round drilling demonstration project in the Pinedale Anticline Field:
http://www.wy.blm.gov/nepa/pfodocs/asu/01ea.pdf

Jonah Infill Project:

Encana release: http://www.encana.com/operations/upstream/us_jonah_blm.html

BLM air quality discussion:
http://www.wy.blm.gov/nepa/pfodocs/jonah/92FEISAirQualSuppleQ-As.pdf

BLM EIS and Record of Decision: http://www.wy.blm.gov/nepa/pfodocs/jonah/

NMOGA Good Neighbors Initiative:
http://www.nmoga.org/nmoga/NMOGA%20Good%20Neighbor%20Initiative.pdf
Wyoming Mule Deer Study Report (1 site)
http://www.west-inc.com/reports/big_game/PAPA_deer_report_2006.pdf
Wyoming wildlife, sage grouse
http://stream.publicbroadcasting.net/production/mp3/wpr/local-wpr-563699.mp3
http://gf.state.wy.us/downloads/pdf/sagegrouse/Holloran2005PhD.pdf
Wyoming wildlife, Bald Eagle http://www.wy.blm.gov/nepa/pfodocs/anticline/seis/06chap3.pdf 3-97
http://www.wy.blm.gov/nepa/pfodocs/anticline/seis/07chap4.pdf 4-123
Wyoming Bureau of Land Management, wildlife monitoring (1site)
http://www.washingtonpost.com/wp-dyn/content/article/2006/08/31/AR2006083101482.html
New Mexico: Comprehensive Wildlife Conservation Strategy (CWCS)
http://fws-nmcfwru.nmsu.edu/cwcs/New_Mexico_CWCS.htm
New Mexico—2003 Bureau of Land Management Resource Management Plan/Environmental Impact Statement, Record of Decision http://www.nm.blm.gov/ffo/ffo_p_rmp_feis/docs/Farmington_ROD.pdf Appendix B

V. Any uncertainty associated with the option
Medium: Depends on opportunities (proposed projects) for implementing incentives in exchange for mitigation activities, on producer willingness to participate, and on BLM/FS state and regional office and tribal policy.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups Impacts from trucks and roads may overlap with the Other Sources work group.

Mitigation Option: Economic Incentives-Based Emission Trading System (EBETS)

I. Description of the mitigation option

The central idea of this option is that inherent economic incentives promote innovative ways to achieve emission reductions, including gains from efficiencies in operation and maintenance and in applications of new innovative engine and control technologies.

This option encourages the use of pollution markets through implementation of an emission trading system (ETS) along with cooperative partnerships to reduce air emissions with the aid of emission reduction incentives. Basically in an emission trading program, the governing authority (e.g., agency) issues a limited number of allocations in the form of certificates consistent with the desired or targeted level of emissions in an identified region or area. The sources of a particular air pollutant (e.g., NOx) are allotted certificates to release a specified number of tons of the pollutant. The certificate owners may choose either to continue to release the pollutant at current levels and use the certificates or to reduce their emissions and sell the certificates. The fact that the certificates have value as an item to be sold or traded gives the owner an incentive to reduce the company's emissions. Simply stated in an ETS, a producer who has low-emission engines could sell emissions credits to a producer who has high-emission engines. Typically, 0.8 units of credit could be sold for each unit of reduction below the standard or reference level. The end result is a ratcheting down of overall emissions. This option does not contemplate multi-pollutant trading, but rather a separate market for each individual pollutant.

Approximately 30 state and federal ETS programs existed or were being developed in the U.S. in the later part of the 1990s. Examples of ETS that have worked reasonably well in achieving emission reductions and providing economic incentives to industry include the Illinois EPA's Emission Reduction Market System (ERMS), Indiana Department of Environmental Management's credit registry trading system, U.S. EPA's Acid Rain Program, and commercial and non-commercial institutions like Chicago Climate Exchange (CCX). In addition, in 2002 the US EPA approved a plan submitted by the WRAP, which contained recommendations for implementing the regional haze rule. The plan included an SO_2 emissions allowance trading program for nine Western states and eligible Indian tribes. As an example, EPA's program took about three years to plan and begin implementing.

The proposed economic incentives based emission trading system (EBETS) mitigation option can be developed or modeled after ETSs which have been successful and tailored to issues specific to the Four Corner region. Emission credits can accrue through a variety of methods that are complementary to or independent of other mitigation options developed herein by the Task Force. For example, credits can be gained through use of partnerships that that provide incentives for voluntary emission reductions, such as in the EPA's Natural Gas STAR Program or New Mexico's VISTAS program (see the IBEMP mitigation option paper, OOP4). Credits for use or sale (e.g., sales within the ETS) can also be acquired through use of tax and/or lease incentives and through the initiatives coming from Small and Large Engine Subgroup (e.g., advanced ignition systems, use of electric engines, centralized large engine from many small engine mode of operations). In addition, opportunities exist for collaboration between engine manufacturers and producers for field testing new engine technology through a swap out program, dirty old for cleaner new. Finally, use of voluntary laboratory testing of a select group of existing engines (e.g. uncontrolled small, <300 hp, engines) could provide a means to identify innovative cost-effective modifications to improve engine efficiency and reduce engine emissions (SERP, 2006).

<u>Benefits</u>: Joint participation by oil and gas, electric power production, and other source category stakeholders provides opportunities for multi-pollutant emission reductions that cover key criteria air pollutants such as NO_x, SO_2, VOCs, $PM_{2.5}$, and PM_{10}. An added benefit could be realized by also including green house gases such as CO_2 and CH_4, in the mix. Examples of the emission reductions that

could be achieved by a well designed and implemented ETS are the 50% reduction from 1980 levels of SO2 emissions from utilities under the ETS within US EPA's Acid Rain Program[1] and the 65% reduction from 1990 levels achieved under the Ozone Transport Commission NOx Program (SERP, 2006).

Tradeoffs: The ETS could be designed to provide for pollutant emission allocation and/or credit tradeoffs (e.g., NOx for SO2 in NOx limited regions) and trades between source groups or categories (e.g., oil and gas NOx with power plant SO_2).

Burdens: The major burden would be administrative in nature. Who would be responsible for designing, setting up and administering the proposed EBETS program and how would it be funded?

II. Description of how to implement

A. Mandatory or voluntary: Participation in the program would be voluntarily.

B. Indicate the most appropriate agency (ies) to implement: The states.

III. Feasibility of the option

A. Technical: The technical feasibility of ETS programs is well established and is in use around the world.

   Differing opinion: Accurately and reliably measuring the emissions from oil and gas sources will prove challenging. EBETSs have had broad success because those that have been established rely heavily on good monitoring and reporting, and it is not clear that such techniques are available for the oil and gas sources of interest. Parametric, as opposed to direct exhaust emissions monitoring is one option, but the less direct/accurate/reliable the measurement, the more likely it is that some offset/discount will be demanded to make up for the uncertainty, e.g., if a source wanted to purchase credits as part of its compliance plan, it would have to purchase two instead of one. Alternatively, sources with relatively weaker emissions monitoring would be allowed to purchase credits, but not sell them. This latter approach was taken in the WRAP SO2 Backstop Trading Program.

B. Environmental: The feasibility in achieving significant emission reductions has been clearly demonstrated through use of well designed and implemented ETS programs. Inclusion and addition of "Best Management Practices," innovative technologies, improved maintenance and other pay-back incentives enhance the feasibility of achieving emission reductions required to meet air quality and visibility enhancement goals in the Four Corners Region.

C. Economic: This program is economically feasible because emission trading provides economic incentives through implementation of complementary voluntary measures that reduce emissions, provide fuel savings, reduce operation and maintenance cost by adoption of BMPs and installation of innovative technologies. One recent study of projected economic gain by 2010 from the continued implementation of the ETS within the Acid Rain Program estimated it would provide an annual economic benefit of $122 billion (in 2000 $) at an annual cost of approximately $3 billion (or a 1 to 40 cost-benefit ratio).

[1] The success of the Acid Rain Program ETS is evident from emissions data, which shows that SO_2 emissions were reduced by over 5 million tons from 1990 levels or about 34 percent of total emissions from the power sector. When compared to 1980 levels, SO_2 emissions from power plants have reduced by 7 million tons or more than 40 percent.

IV. Background data and assumption used

1. United States Environmental Protection Agency (USEPA) Acid Rain Program < http://www.epa.gov/airmarkets/arp/index.html>
2. Illinois Environmental Protection Agency Emission Reduction Market System (ERMS) <http://www.epa.state.il.us/air/erms/>
3. Argonne National Laboratory, Strategic Emission Reduction Plan, Draft, 2006.
4. Chicago Climate Exchange < http://www.chicagoclimatex.com/>

V. Any uncertainty associated with the option Medium to high.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups

A key crossover issue to establishing and implementing an effective EBETS is the facilitation of voluntary participation of electric utilities and other major source groups. This will provide the anticipated needed trade-offs in air pollutants (e.g., NOx and SO_2) that participation by one or a limited number of source groups may not be able to provide.

Mitigation Option: Tax or Economic Development Incentives for Environmental Mitigation

I. Description of the mitigation option

This option provides for regulatory agencies and industry working together to utilize various legislative (state/federal/tribal) processes to achieve real emissions reductions. Emission reductions would be achieved by providing economic incentives that would encourage the industry to utilize lower emission internal combustion engines in various applications.

Emission reductions could be achieved through reducing the number of trucks in the field. This could be accomplished by providing incentives for companies to install underground piping in order to dispose of produced water. Criteria pollutants could be reduced by installing lower emissions compressor engines. Industry could be encouraged to install such engines by implementing tax incentives as described below.

Tax incentives provide economic relief to industry by reducing or eliminating taxes on certain equipment or activities. The equipment or activity must provide a recognized environmental benefit to the taxing entity that grants the incentive. Some examples of tax incentives currently being utilized are: (1) allowing costs of retrofitting existing engines or installing new engines to be fully deducted in the year they are incurred rather than being capitalized (2) tax credit certificates issued to program participants, which can be redeemed over a specified period of time (3) income tax credits upon installation of approved equipment.

The air quality benefits include net reduction of emissions, primarily of nitrogen oxides. However, reductions in sulfur oxides, greenhouse gas emissions and particulate matter emissions can also be calculated. Only positive environmental impacts have been identified. It is not anticipated that this strategy would cause any negative impacts, other than increased costs to industry. This strategy specifically provides for relief from such economic impacts.

Economic burdens include the cost to the oil and gas industry, engine manufacturers and other interest groups to develop and lobby legislative proposals. New technology would be more efficient, possibly resulting in increased production and reduced costs. The increased revenue would provide some offset to the initial costs of installation or retrofitting. Economic burden to the taxing entity would also occur. The taxpayers would, in effect, be subsidizing industry efforts to install or retrofit equipment to achieve lower emissions. Achieving taxpayer approval for such a subsidy might prove difficult.

Assistance from the Cumulative Effects Work Group could be helpful in estimating the potential cost-benefit of this option.

II. Description of how to implement

A. Mandatory or voluntary: Participation by industry or other groups would be voluntary, both in working to establish tax/economic development incentives and in taking advantage of such incentives.
B. Indicate the most appropriate agency(ies) to implement**:** States of Colorado and New Mexico. Counties of San Juan, NM; La Plata, CO; and other counties in the Four Corners area of impact. Indian tribes, including Jicarilla, Ute Mountain Ute, Southern Ute, Navajo, and others. These groups would need to work with state legislatures and/or Congressional representatives in getting sponsors to help draft an energy bill that includes tax incentives for improving Four Corners air quality.

III. Feasibility of the option

A. Technical: Many models of tax and economic development incentives are available. A list of some models follows, with more details contained in an Appendix to this document.

i. Mineral Tax Incentives and the Wyoming Economy, May 2001, is an economic model. http://legisweb.state.wy.us/2001/interim/app/reports/mineraltaxincentives.htm

ii. Brownfields Tax Incentive (1997 Taxpayer Relief Act P.L. 105-34). This model allows costs to be fully deductible in the year they are incurred, rather than having to be capitalized.

iii. New York State Green Building Initiative. This tax credit program was developed by New York State Department of Environmental Conservation as per 6NYCRR Part 638. Tax credit certificates are issued and can be redeemed at any time over a designated period (i.e. 2006 – 2014).

iv. Montana Incentives for Renewable Energy include property tax exemptions, industry tax credit, venture capital tax credits, and a low interest revolving loan program, special revenue local government bonds, and streamlined permitting processes for participants, income tax credits for retro-fitting equipment.

v. State of Virginia House Bill 2141, July 1997 allows the local governing body of any county, city, or town, by ordinance, to exempt, or partially exempt property from local taxation annually for a period not to exceed five years.

vi. US EPA's Voluntary Diesel Retrofit Program is a non-regulatory, incentive-based, voluntary program designed to reduce emissions from existing diesel vehicles and equipment by encouraging equipment owners to install pollution reducing technology. This option would easily fit into the "partnership" mitigation option. However, it is also a model for the type of equipment that might qualify for a tax incentive.

vii. Philippines Department of Natural Resources developed a single document that consolidates all tax incentives for air pollution control devices. Not new incentives, but a compilation of existing programs.

viii. Western Regional Air Partnership diesel Retrofit program for diesel engines could be used as a model for other internal combustion engines. The guidance document for developing a retrofit program is found on the WRAP website. See Appendix for information. This option would easily fit into the "partnership" mitigation option. However, it operates similar to a tax incentive program and gives an example of how to set up a workable program.

B. Environmental: The environmental benefits of pollutant emissions reductions are well documented.

C. Economic: The entire concept of this mitigation option is that it must be economically viable.

IV. Background data and assumptions used

See Appendix for background studies.
Cooperation between the regulated community; local, state and tribal governments; and equipment manufacturers would have to be garnered in order for this option to work.

V. Any uncertainty associated with the option Medium

VI. Level of agreement within the work group for this mitigation option

The three member drafting team expressed no disagreement with this option.

VII. Cross-over issues to the other source groups

These tax incentive programs could also apply to other sources, such as power plants or vehicles.

APPENDIX

Mineral Tax Incentives and the Wyoming Economy, May 2001, is an economic model. http://legisweb.state.wy.us/2001/interim/app/reports/mineraltaxincentives.htm
This model can be used to show the effects of all tax incentives previously granted, as well as the effects of hypothetical tax incentives or tax relief that might be considered in the future. Impacts include reduction in taxes; increased production; effects on federal, state and local government revenues.

Brownfields Tax Incentive fact sheets (EPA 500-F-03-223, June 2003) and incentive guidelines (EPA 500-F-01-338, August 2001) can be found on US EPA's website at www.epa.gov/swerosps/bf/bftaxinc.htm There are also numerous case studies listed on this site as well as federal resources.

New York State Green Building Initiative credit certificates can be re-allocated to secondary users, if the initial recipient cannot utilize the entire credit amount. Information available at www.dec.state.ny.us/website/ppu/grnbldg/index.html or Pollution Prevention Unit (518) 402-9469; NY business tax hotline (518)862-1090 x 3311

Montana Incentives for Renewable Energy http://deq.mt.gov/Energy/Renewable/TaxIncentRenew.asp

Virginia property tax exemptions for the Voluntary Remediation Program http://www.deq.state.va.us/vrp/tax.html

US EPA's Voluntary Diesel Retrofit Program information at http://www.epa.gov/otaq/retrofit/retroverifiedlist.htm Includes a list of approved retrofit technology.

Philippines Department of Natural Resources lists many tax incentive and economic incentives at http://www.cyberdyaryo.com/features/f2004_0624_03.htm Also included are numerous links to related sites.

Western Regional Air Partnership guidance document for diesel retrofit programs can be found at http://www.wrapair.org/forums/msf/offroad_diesel.html

Mitigation Option: Voluntary Partnerships and Pay-back Incentives: Four Corners Innovation Technology and Best Energy-Environment Management Practices (IBEMP)

I. Description of the mitigation option

This option encourages establishment of partnerships between oil and gas producers and federal, state and local agencies and with engine manufacturers. Examples of such voluntary partnerships that have worked successfully in reducing emissions and providing cost benefits to industry include the U.S. EPA's Natural Gas STAR Program, the New Mexico's Voluntary Innovative Strategies for Today's Air Standards (VISTAS) Program, Green Power and Combined Heat and Power Partnerships. The Natural Gas STAR Program is one of many voluntary programs established by the U.S. Environmental Protection Agency (EPA) to promote government/industry partnerships that encourage cost-effective technologies and market-based approaches to reducing air pollution. There are seven San Juan Basin producers[1] that are currently active members of the Natural Gas STAR Program. The VISTA Program is modeled after Natural Gas STAR.

This option involves establishing new partnerships or extending existing partnerships that encourage voluntary measures that reduce emissions and provide industry payback through improved operation and maintenance efficiencies. The IBEMP option is based on and is intended to extend upon the successes achieved in EPA's Natural Gas STAR Program and to complement the newly established VISTAS Program.

The central ideas of this option

- Increasing efficiency will result in more productivity, less emission, and increased revenue.
- Complementing EPA's Natural Gas STAR Program and VISTAS program to focus on the pollutants not covered in these programs
- Collection and use of the Best Management Practices (BMPs) from around the world, latest innovative technologies, and innovative solutions found by IBEMP members.

The air quality benefits include reduction of criteria pollutants such as NOx, SO_2, $PM_{2.5}$, PM_{10} as well as green house gases CO_2 and CH_4. The success of the EPA's Natural Gas STAR Program is well documented. According to the EPA's Gas Program, "Since the Program's launch in 1993, Natural Gas STAR Partners has eliminated more than 220 billion cubic feet (Bcf) of methane emissions, resulting in approximately $660 million in increased revenues." One Natural Gas STAR Partner has achieved the 18% to 24% fuel saving and reduction of 128 Mcf of methane emission per unit per year after installing an automated air to fuel ratio (AFR) control system called REMVue. According to engine manufacturers, new generation engines have benefits over older generation such as low operating cost, high thermal efficiency, low emissions, maintenance simplicity, and low repair cost which will help in recovering the cost of investment faster. An example of rapid improvement in the engine technology is the new Cummins-Westport engine, which is capable of peak thermal efficiency of close to 40% with 0.01 g/bhp-hr PM and 0.2 g/bhp-hr NOx emission. Even though Cummins-Westport engines and new generation engines from other engine manufacturers are geared towards transportation sector at present because of tighter emission standards, the improved engine technologies will help reduce the pollution in the other industrial sectors as the demand grows for efficient engines.

[1] BP, Burlington Resources, ConocoPhillips, Devon Energy, Williams Production, Energen Resources, and XTO Energy

Under this option, the time period to offset the cost of the replacing old engines with a new generation engines can be estimated through analysis of data from laboratory testing. Such data may be available from engine manufacturers or obtained through independent laboratory engine performance tests. The voluntary comparative laboratory performance and emissions testing (e.g., operating cost) and documentation would be performed by an independent test laboratory. In addition, voluntary laboratory and field-testing of a select group of existing engines (e.g., uncontrolled small, < 300 hp, engines) could provide a means to identify cost-effective modifications to improve engine efficiency and reduce engine emissions (Lazaro 2006, SERP).

Under this program the increased revenue from methane mitigation and fuel and maintenance savings can offset the cost of investment in the BMP and new technologies or equipment. In addition, under the proposed IBEMP option, partner members' mitigation efforts will be fully recognized and promoted similar to the recognition of partner contributions under EPA's Natural Gas STAR Program and New Mexico's VISTAS Program. Mitigation efforts can be recognized through awarding of emission credits (which can be traded in an emission market system, OOT-3). These efforts will also provide benefits to members through improved public and investor relations.

Since the IBEMP option is a voluntary program, participating members will have control or choice on mitigation decisions that are made. This provides opportunities for choices that provide a return on investments in best management practices and on new equipment and technology. As such, this option does not impose a burden on participating partners. Although, being a partner under this option would not relieve an operator from complying with non-voluntary measures or options, BMPs or other commitments made voluntarily under this option may facilitate compliance with other mandatory measures that may be adopted or come into play.

II. Description of how to implement

A. Mandatory or voluntary: The participation in the program is voluntarily

B. Indicate the most appropriate agency(ies) to implement: Through the New Mexico Environment Department under or a part of its VISTAS Program and/or in partnership with the Colorado Department of Public Health and Environment. The USEPA Gas Program may also be interested in collaborative partnerships with the Four Corners Air Quality Task Force.

III. Feasibility of the option

A. Technical: The success of the EPA's Natural Gas STAR Program is a clear indicator of the technical feasibility of this program.
B. Environmental: The Best Management Practices, including equipment upgrades are well established in the oil and gas industry and adoption of these measures will provide opportunities for significant and achievable emission reductions.
C. Economic: This program is economically feasible because innovative technologies and BMPs will result in increased productivity, fuel saving, and environmental benefits, which in return offset the cost of investment. The previously referenced EPA Natural Gas STAR Program example illustrates that significant savings can be achieved in reduced fuel consumption (e.g., in one case that covered 51 engines reduction in excess of 2,900 MMcf or an average of 78 Mcf per day per engine, when adjusted for load, was achieved over a two-year period). The final payout period was 1.4 years by taking into consideration of fuel saving of $4.35 million at a nominal value of $3/Mcf.

IV. Background data and assumptions used

1. United States Environmental Protection Agency (USEPA) Natural Gas STAR Program <http://www.epa.gov/gas/>

2. New Mexico San Juan Voluntary Innovative Strategies for Today's Air Standards (VISTAS) <http://www.nmenv.state.nm.us/aqb/projects/SJV/index.html>
3. Engine Manufacturers: <www.cat.com>, <www.cummins.com>, <www.cumminswestport.com>.
4. Argonne National Laboratory, Strategic Emission Reduction Plan, Draft, 2006
5. Near-term commercial availability of small clean efficient engines
6. Near-term commercial availability of advanced engine technology

V. Any uncertainty associated with the option Low to medium.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups

Establishing and implementing an effective IBEMP is the facilitation of voluntary participation of San Juan oil and gas producers. There are no key crossover issues with other source groups.

Mitigation Option: Voluntary Programs

I. Description of the mitigation option

Overview

This option describes voluntary programs to implement mitigation strategies and achieve air quality benefits that are above and beyond the requirements of regulations and permits. This option is not meant to replace the *Voluntary Partnerships and Pay-back Incentive* mitigation option, nor is this option meant to indicate voluntary implementation should be applied to existing or future requirements necessary for improvement of air quality. There are situations in which mandatory measures are the only system that will result in emissions reductions that are high-impact, consistent, and necessary. There are also situations in which voluntary implementation of strategies may be a method to achieve emissions reductions in a time- and cost-effective manner. Voluntary programs allow participants to demonstrate their commitment to the issue and to local communities. Challenges to success with voluntary programs include publicizing a program to make it well-known, creating a list of strategies and technologies that may be implemented voluntarily, offering incentives sufficient to attract program participants, and quantifying emissions reductions adequately and consistently to estimate results.

Air Quality and Environmental Benefits

- Air quality improvement because voluntary measures would achieve emissions reductions beyond regulatory and permitting requirements.
- Depending on strategy/technology, other environmental benefits may exist.

Economic

- Capital investment from participants for voluntary measures and reporting.

Trade-offs

- Air quality improvement
- Positive public relations
- Agency's costs for administration and tracking.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary. The New Mexico Environment Department already administers a voluntary program called VISTAS (Voluntary Innovative Strategies for Today's Air Standards) that is modeled after EPA's Natural Gas STAR Program. To increase implementation, the agency could compile of list of mitigation options not otherwise required by regulation or permit, as a list of "qualifying" voluntary measures for VISTAS. More information about VISTAS is available at: http://www.nmenv.state.nm.us/aqb/projects/SJV/index.html. Quantification of benefits and measurement of other results is essential to ensure accountability in a voluntary program and increase likelihood of success of the program. In addition, participants or the administrator of a voluntary program should describe voluntary actions by producing "Lessons Learned" papers, which are short descriptions of practices and technologies employed, benefits and challenges, feasibility, and implications for future use of the same voluntary actions.

B. Indicate the most appropriate agency(ies) to implement: State Environmental Agencies

III. Feasibility of the option

A. Technical: Good feasibility due to flexibility and choices regarding participation and specific technology(ies) implemented. Potential voluntary measures for the oil and gas industries may include, but are not limited to, the following:

- Plunger lift cycles for removal of liquid buildup and minimizing well blowdowns.
- Device on tanks to control over-heating, such as bands of insulation.
- Electrification where possible.
- Centralization of tank batteries to decrease truck traffic.

B. Environmental: Excellent feasibility, however environmental benefits depend on control strategies. Select control strategies may have other air or non-air environmental impacts, such as SCR's ammonia slip.

C. Economic: Feasibility depends on incentives. Economic feasibility often increases in response to incentives. Participation in voluntary programs for companies is often based on a cost/benefit economic analysis, and incentives can provide a deciding factor. Potential incentives would be determined by the implementing agency and may include the following:

- "Good Citizen" marketing
- Alternative to regulation, if any exist
- Paybacks/savings
- Consideration for expedited permits, if possible
- Parametric monitoring less strict or other requirement leniency, if possible
- Tax credit/royalty rate reduction
- For Federal land, modification in standard stipulations, if possible.
- "Credit" given like an Environmental Management System on compliance history

IV. Background data and assumptions used

Natural Gas STAR and San Juan VISTAS, both voluntary air programs in the Four Corners region.

V. Any uncertainty associated with the option High. Voluntary programs do not guarantee emissions reductions, nor are emissions reductions enforceable. Quantify of reductions through reporting may lessen uncertainty but do not guarantee or enforce reductions.

VI. Level of agreement within the work group for this mitigation option Medium. This option write-up stems from a discussion at the November 8, 2006 meeting of the Oil and Gas Work Group.

Some members of the work group expressed concern that mandatory application of the strategies outlined in this document prior to analysis by a regulatory agency may preclude consideration of advantages and disadvantages from voluntary programs. There was also some discussion of the concept of criteria for establishing whether a mitigation strategy is applied under voluntary or mandatory conditions should be developed to enhance capability for implementation of the options. These criteria would provide an important tool to agencies considering options by better defining feasibility. Additionally, voluntary application of the mitigation strategies would facilitate the development and efficient implementation of these options via a "lessons learned" approach where mandatory application may prematurely dictate the method of implementation.

VII. Cross-over issues to the other source groups

If a voluntary program has a wide range of participants, there are many cross-over issues to other source groups in terms of what voluntary measures could be implemented by those sources.

Mitigation Option: Cumulative Inventory of Emissions and Required Control Technology

I. Description of Mitigation Option

The Four Corners Region is a hotbed of oil and gas activity. There are more than 20,000 oil and gas wells in the San Juan Basin and at least 12,500 additional new wells are proposed within the next 20 years. Oil and gas facilities are being located in remote areas and in neighborhoods and cities. The City of Bloomfield, NM, population of 7,200 people, has at least six major oil and gas processing facilities in very close proximity. A large elementary school near the cluster of these facilities north of Bloomfield was evacuated in 2006 due to an accidental release of noxious emissions from one of these gas plants.

A cumulative inventory of total emissions from the large oil and gas facilities near densely populated areas should be conducted prior to the permitting of additional facilities. It has been reported that at least one new, large, petroleum processing facility is on the drawing board for the Bloomfield area.

All oil and gas facilities, large or small, should be required to report all emissions to appropriate governing agencies annually. A cumulative inventory of emissions is necessary.

Installation of best available technology emission control equipment on ALL oil and gas facilities should be MANDATORY to greatly reduce the release of pollutants into the environment. All internal combustion engines should be required to be fitted with catalytic converters.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory.

B. Indicate the most appropriate agency (ies) to implement: States of New Mexico and Colorado.

III. Feasibility of the option

A. Technical: is not clear whether the intent was to have a yearly report of emissions output based on continuous emissions monitoring for all pollutants (very expensive), or if the intent was to have the operators estimate the amount of emissions based on what sources had been operational during the year. Option also needs to define what levels of the given pollutants would be acceptable to assess feasibility.
B. Environmental: None
C. Economic: None

IV. Background data and assumption used

Bloomfield area ozone levels are already periodically high according to monitoring. Any consideration of permitting additional large oil and gas facilities near Bloomfield should include risk of increasing levels of ozone.

An example:
The North Crandall Compressor Station located within the City of Aztec is permitted by NMED Air Quality Bureau at 176.3 tons/yr (tpy) of Nitrogen Oxides (NOX), 39.4 tpy of Carbon Monoxide and 75.9 tpy of Volatile Organic Compounds (VOC's). There is a warning sign on the fence that states "Warning Hazardous B.T.E.X. emissions may be present." B.T.E.X. compounds are toxic to humans and wildlife. Several homes are located near this facility.

In comparison to the refineries and gas processing facilities in the Bloomfield area, the Williams Crandall Compressor Station is small but it is permitted to emit about 292 tons of pollutants per year into the atmosphere. Cumulative permitted emissions from the very large Bloomfield facilities are unavailable at this time.

Oil and gas facilities are sources of many hazardous pollutants such as NOX, SOX, VOC's, methane, hydrogen sulfide, etc. Many of these pollutants contribute to respiratory diseases, cardiac diseases and some of them are carcinogens. Hydrogen sulfide is a deadly neurotoxin.

V. Any uncertainty associated with the option None.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups TBD.

Mitigation Option: Mitigation of Hydrogen Sulfide

I. Description of Mitigation Option

Hydrogen sulfide (H_2S) is a deadly neurotoxin. Since H_2S contamination is becoming more widespread, for the safety of the public and the oilfield employees ALL wells should be tested for H_2S by the well operators at least twice per year and the test results reported to appropriate agencies.

The companies provide H_2S training and monitors for the employees. The employees are trained to be aware of H_2S, but the general population is not. The typical rotten egg smell is a familiar warning to oilfield employees, but the general population who lives in close proximity to H_2S wells are not informed about the dangers of an H_2S release.

Public information programs on the dangers and toxicity of oil and gas pollutants and most importantly H_2S, must be made available to the people. Ideally, gas wells and refineries should be isolated away from the general population; however, oil and gas facilities are being established in populated areas and vice versa. Houses are being built next to oil and gas sites. For the health of the public, exposure to H_2S and other petroleum related toxics must be prevented.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory.

B. Indicate the most appropriate agency (ies) to implement: The companies and the States of New Mexico and Colorado.

III. Feasibility of the option

Not considered.

IV. Background data and assumption used

For H_2S information, do a Google search on Dr. Kaye H. Kilburn MD, and Professor of Medicine at the University of Southern California. He is a leading researcher on chemicals such as hydrogen sulfide and diesel exhaust.

The Bureau of Land Management has been collecting data on the wells contaminated by hydrogen sulfide in the San Juan Basin.

Quick statistics are as follows:

- More than 375 wells test positive for H_2S
- H_2S is present in at least 5 formations
- 11 producers have reported H_2S wells
- A lot of the small producers did not report, so these numbers are likely higher.

Sour gas (H_2S) fields are common in Colorado and New Mexico. New Mexico has a State Regulation with an ambient air quality standard for H_2S; however, it is reported that NMED does not have H_2S measuring equipment. H_2S must be closely monitored and controlled by the companies and the State and Federal agencies. It can be deadly.

V. Any uncertainty associated with the option TBD.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups TBD.

Mitigation Option: Encourage States Importing San Juan Basin Natural Gas to Require Pollution Control at the Source

I. Description of the mitigation option

States that import San Juan Basin natural gas should require the gas be produced and transmitted in an environmentally clean method. End users should have a responsibility for the sources of pollution generated from natural gas production.

Recent California legislation banning importation of power from sources that generate more greenhouse gases than in-state natural gas-fired plants leads to this related issue.

Much of the natural gas used in these plants as well as in the residential sector is imported from other states or other countries. One published article[1] states that 85% of the natural gas used in California is from out-of-state and that one-quarter of this comes from the San Juan Basin. Other states may also be using San Juan Basin natural gas. It is disingenuous for states to claim to be producing clean power or using clean gas for residential use when the production of fuel for that "clean" power plant or clean burning appliance is creating serious air and water quality problems at the source of the fuel. If the user states are seriously concerned about improving air and water quality they should address out-of-state impacts as well as in-state impacts.

II. Description of how to implement

A. Mandatory or voluntary:
   Adoption of a "clean fuel import policy" by user states would necessarily have to be voluntary. However, the application of such a policy by a user state, once adopted, could and should be mandatory for fuel importers.

B. Indicate the most appropriate agencies to implement:
   Implementation of the policy in user states could be by the regulatory agencies or commissions charged with oversight of investor-owned or publicly-owned electric utility systems. In some cases legislation may be necessary to implement this policy.
   There is a need to develop an inventory, state-by-state, of customers who are importing natural gas from wells in the San Juan Basin. The first step in implementation would involve contacting user states and urging adoption of policy or legislation requiring importation of "clean" natural gas; a definition of "clean" must be developed.

III. Feasibility of the option

A. Technical:
   It may be difficult to develop a good working definition of what constitutes acceptably "clean" natural gas. This is also a legal issue and one must work within the framework of the Federal Clean Air Act and Clean Water Act as well as individual state statutes.

B. Environmental:
   Should be feasible

C. Economic:
   Could eventually lead to higher costs for electricity in user states due to the rightful inclusion of environmental costs of fuel production.

D. Political:
   Could be very difficult to implement in some states

IV. Background data and assumptions used

Assumption that most natural gas produced in the San Juan Basin is exported to other states. The figures cited in Section I should be checked/verified.

V. Any uncertainty associated with the option
Yes; response of user states unknown.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other Task Force work groups
Significant cross-over to the Power Plants and Oil & Gas Work Groups

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[1] *High Country News*, Dec. 25, 2006, p. 12.

OIL & GAS: PUBLIC COMMENTS

Oil & Gas Exploration & Production Public Comments

Comment	Mitigation Option
If "many companies BMPs in place already," then why does a mandatory approach to BMPs seem implausible. This should be a cost of doing business in this area; a cost that is well-absorbed by most other companies.	Best Management Practices (BMPs) for Operating Tank Batteries
VRU's have one big technical problem not addressed, the introduction of air in the gas. Air is made up of Nitrogen and Oxygen two contaminates that the gas pipeline companies refuse to take into their system. If one VRU allows air to enter the gas system, then the whole gas system must be shut down or flared in the field. The gas companies must be forced to take air in reasonable quantities into their system. The gas pipelines will argue that it is unsafe, if that is true then all the gas supplying houses in the Colorado front range must be shutdown because air is added to improve quality.	Installing Vapor Recovery Units
In the 60's and 70's this type of water removal was tried in the northern Rockies. The amount of saltwater disposal was huge and the beds may only last a day or two before they must be changed.	Dehydrators / Separators / Heaters
Glycol pumps are a critical item and any replacement system must have a high reliability. 5KW generators will had NOx, CO, CO2 and decrease reliability. Kimray pumps with flash gas separators reduce emissions and keep the system reliable. the gases recovered from the pump gas separator can be used for fuel MOST of the time. In some cases where the gas stream is high in liquefiable hydrocarbons (those with molecular weights higher than 40) the pump gas separator vapors will not burn reliably or completely cause unreliable operators and increased emissions. In the case of gases with high liquefiable content, vent gases need to be flared (burned).	Zero Emissions (a.k.a. Quantum Leap) Dehydrator
We strongly agree that an initial voluntary monitoring effort, followed by mandatory reporting and monitoring requirements, should be initiated by the operators to measure concentrations and species of VOCs and HAPs and other flaring by-products.	Venting versus Flaring of Natural Gas during Well Completions
We strongly agree that co-location and centralization of new oil/gas field facilities should be voluntarily implemented by operators. We also agree with the approach of state and federal agencies and mineral management agencies proactively integrating this approach into planning and permitting processes.	Co-location / Centralization for New Sources
The present laws will not allow this option. TEG (glycol) units must be permitted at a maximum rate. In the Rockies the maximum rate is only required for a few months during the year. Good operators adjust their pumps as needed to save fuel and lower emissions, but they get not credit for doing so because their permits are set. GLYCALC uses all kinds of default assumptions, this does not replace good engineering and the ability to make real life adjustments. Other design and simulation programs should be allowed without any legal ramifications.	Control Glycol Pump Rates
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Control Glycol Pump Rates
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Convert High-Bleed to Low or No Bleed Gas Pneumatic Controls
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Optical Imaging to Detect Gas Leaks

Comment	Mitigation Option
Instrument gas or instrument air is used to control facilities. These controls maintain the emission control system, gas quality controls and safety shutdown systems. If the instruments air/gas system lacks sufficient quantity and quality, the controls will fail and emissions, quality and safety devices can fail with undesirable results. At small and remote sites air compressors will be unreliable and gas must be used.	Convert Gas Pneumatic Controls to Instrument Air

Oil & Gas Stationary RICE Public Comments

Comment	Mitigation Option
The SUGF agrees that new air quality management strategies such as this option should be implemented to address cumulative air quality impacts. It is highly recommended that this option be considered by the regulatory agencies and be applied to both new and existing engines, particularly units of less than 300 horsepower. Although horsepower levels are lower and operating hours may be limited, emission rates of these smaller units are higher than larger units. As a single source, emissions may be minimal, but collectively with other area sources it may have a cumulative affect.	Industry Collaboration
Comments below are specific to the mitigation option as currently written, which assumes the power requirement would come from the power grid. A second alternative is also provided below as a sub option assuming the power comes from on-site generators. We recommend including both alternatives to this option. Comments are also provided on the analysis of this option under the cumulative effects section of the public draft report. Install Electric Compression (re-label as Alternative 1 - Power Grid, see recommended Alternative 2 addition below after comment # 6) 1. The overview is not consistent with overviews written for other mitigation options covered in the Task Force Report. As written, the overview presents a rather biased view on the viability of this option. The overview should provide a description of the option without any discussion about the option's technical or economic feasibility. Possible physical restriction or modification requirements on installation for specific compressors should be removed and discussed under Sec III. Feasibility of the option, A. Technical. The last two sentences on the electric grid should also be moved to the feasibility discussion or deleted. Under the mitigation option overview, we recommend inserting the following: The selection of combustion engines for electric compression should be on case-by-case basis which will allow the flexibility of evaluating necessary compressor interface modifications such as re-gearing to accommodate electric motors. 2. The discussion and emission table under Air Quality/Environment is inconsistent with discussions covered in the other mitigation options and should be deleted. Please see our comments on the Cumulative Effects section analysis of this option. The nationwide averages of emissions from power plants operated by the three identified companies would not be representative of the power supplied from the Western Power Grid. We recommend inserting the following under the mitigation option overview:	Install Electric Compression

Comment	Mitigation Option
The noise from continuously running internal combustion engines can be an issue for the nearby residents. The switch to electric motors will also help cut down the noise in the oil and gas operation. 3. The economics as written only covers the costs of the option if implemented. To provide a balance picture both costs and economic benefits should be covered. The following points should be included in the discussion: a. In case of electric motors connected to power grid, there is virtually no maintenance cost. b. The electric rates in the night are cheaper compared to peak times. This will result in additional saving for oil and gas industry. c. The need for less maintenance of electric motors and localized electric grid will result in fewer maintenance trips for the oil and gas workers which will help in controlling dust as well as minimize impact on the wild area in the four corners region. In the second bullet not sure what specific maintenance and repair costs we be borne by producers that are associated with the electric power source for electric compression. Maintenance and repair of substations and transmission lines, from the grid to substation, are typically borne by electric generators and included in rates to consumers. The last bullet on suppliers/manufacturers is more an implementation issue than an economic issue. We recommend moving this discussion to description on how to implement. 4. Tradeoffs - We recommend striking any reference to new co-generation plants as means to supply power for electric compression, since the electric compression option requires no thermal power. As previously stated current plans for electric power generating within the western regional power grid should be adequate to meet even the most optimal electric compression demand that might develop. 5. Burdens - Since implementation of electric compression is voluntary the producers can evaluate which compressor conversions to electric are economically feasible. Economic burdens over the long term can be minimized and possibly turned into economic gain based on careful evaluation of return on capitol expenditures (e.g., lower electric motor vs. RICE engine maintenance costs). The assumed requirement for new electric power generation to support electric compression is speculative, since the degree of implementation of this option producer specific. We recommend deleting the sentence on capitol investment for new power plants. Also, existing plans for new generation may be sufficiently adequate to meet reasonably anticipated power requirements for implementing this option. We recommend consultation with the Power Plant Workgroup. 6. II. Description of how to implement and feasibility of option - See above comments. 7. III. Feasibility of the option, C Economics - On economics, we agree that costs need to be evaluated, including the economic benefits, as previously mentioned. The need for modeling (air quality) to evaluate the air quality	

Comment	Mitigation Option
benefits is true about all of the options. Also, the planned modeling to address cumulative regional air quality impacts is discussed elsewhere in the draft report. We recommend deleting the sentence. ON-SITE ELECTRIC GENERATOR ALTERNATIVE TO GRID POWERED ELECTRIC COMPRESSION As written the current option identifies only one source of electric power, power from the grid. A second alternative to this option would be to supply power to the electric motors using local dedicated low-emission natural gas lean-burn electric generators. The electric compression using the lean-burn electric generator should be included as a second alternative for the "Install Electric Compression" mitigation option. We recommend that the Four Corners Air Quality Task Force add the following language to the Install Electric Compression mitigation option: Mitigation Option: Install Electric Compression (Alternative - On-Site Generators) I. Description of the mitigation option Overview - As an alternative to grid power dedicated on-site natural gas-fired electrical generators can be used to supply power to electric motors that replace the selected RICE compression engines. The electric motors would be rated at an equivalent horsepower to that of RICE engines currently used for gas compression. The power sources for the electric compression could consist of a network of on-site gas-fired electrical power generators. The alternative could be expanded to include consideration of replacement of other engines, such as, gas-fired pump-jack engines used as "prime-movers." The currently available gas electric generator run on variety of fuels including low fuel landfill gas or bio-gas, pipeline natural and field gases. The gas electric generators are available in the power rating from 11 kW to 4,900 kW. Decisions on the use of on-site generators to replace natural gas-fired engines and the number of generators required would depend on a number of factors, including the proximity, spacing and size of existing engines. As a simple example using the conversion factor of 1 MW = 1,341 HP, adding a 1 MW natural gas-fired generator could replace an inventory of approximately 33 small (40 hp) internal combustion engines if these were reasonably close proximity, say spaced within a one or two mile radius. However, in "real world" operations, there will be several factors involved in determining the number of required gas-fired electrical generators; such as transmission loss, ambient operating temperature, load operating conditions, pattering of applied loads, etc. Air Quality/Environmental Benefits The emissions from gas electrical generators are relatively low compare to smaller internal combustion engines because of new technology and ability of controlling emission from big engines. For example a Caterpillar G3612 gas electrical generator with power rating of 2275 kW emits 0.7 gram/hp-hr NO_x at 900 rpm which is equivalent to 0.0009387 g/W-hr. For comparative illustration with alternative 1, if you assume …. As stated in the mitigation	

Comment	Mitigation Option
option; "Control Technology Options for Four Corners Power Plant" (FCPP), the NOx emission from FCPP is approximately 0.54 g/mmBtu. Based on the assumption that efficiency of FCPP is 40%, the NOx emission from FCPP is approximately 0.002099 g/W-hr. This comparison shows that the gas electrical generator is more environmentally friendly then using power from a coal based power plant. The baseline average emission for the Western Grid should be used to calculate the real emission difference between installing a lean burn electric generator to replace combustion engines. The noise from continuously running internal combustion engines can be an issue for the nearby residents. The switch to electric motors will also help cut down the noise in the oil and gas operation. The need for less maintenance of electric motors and lean burn electric generator will result in fewer maintenance trips for the oil and gas workers which will help in controlling dust as well minimize the impact on wild area in the four corners region. Economics The initial capitol cost of installing gas electrical generator and electrical motor would be relatively high. As an example, a generator of 1 MW capacity can approximately support 33 combustion engine of 40 HP. A general purpose 40 HP engines costs about $1200.00 which results in capital cost of $39,600 for replacing 33 internal combustion engine with electric motors. The approximate cost of a 1.2 MW gas-fired generator is $430,000. The total capital cost for replacing 33 engines with a gas fired generator will be about $470,000. However in long term the benefit in terms of emission reduction and saving in maintenance cost should help in recovering the initial capital cost. The maintenance cost of one big generator is cheaper than maintenance of many smaller internal combustion engines. The cost of running electrical wires to connect electric motors will much less than currently installed pipelines to carry natural gas for the small rich burn combustion engines. Tradeoffs In case of gas electric generators, there will be shift of emission from many internal combustion engines to one or several big internal combustion engine(s). There would be a net reduction in emissions which will depend on degree of conversion that each producer deems economically feasible. The cost and affects of running transmission lines from generator(s) to power electrical motors for gas compression needs to be evaluated. Burdens The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry. II. Description of how to implement	

Comment	Mitigation Option
A. Mandatory or voluntary: Voluntary, depending upon the results of monitoring data over time. B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies. III. Feasibility of the option A. Technical: The feasibility mainly depends on the close proximity of replaceable internal combustion engines and operating conditions of internal combustions engines in order of selection of gas electrical generator. The power, transmission line and substation requirements for on-site lean-burn generator system would need to be carefully considered in deciding the feasibility of this option. B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Emissions from on-site electric generators would more than off-set the natural gas-fired engines that could be targeted for replacement (e.g., uncontrolled compressor engines or small rich burn pump jack engines). C. Economic: Depends upon economics of ordering electrical motors, the ability of the grid system to supply the needed capacity and the cost to obtain right of way to drop a line to a potential site. Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small. IV. Background data and assumptions used The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff. Gas electrical generator information was obtained from Caterpillar's Website. V. Any uncertainty associated with the option (Low, Medium, High): Medium based upon uncertainties of obtaining electrical easements from landowners and/or land management agencies. VI. Level of agreement within the work group for this mitigation option TBD VII. Cross-over issues to the other source groups (please describe the issue and	
The SUGF agrees that implementation of this federally mandated level of emission control will minimize emissions from newly manufactured, modified and reconstructed engines after their respective effective dates.	Follow EPA New Source Performance Standards (NSPS)

Comment	Mitigation Option
The SUGF supports the control technology options listed above as the SUGF supports usage of Best Available Control Technologies on internal combustion engines located within the exterior boundaries of the Southern Ute Indian Reservation.	Use of SCR for NOx control on lean burn engines Use of NSCR / 3-Way Catalysts and Air/Fuel Ratio Controllers on Rich Burn Stoichiometric Engines Use of Oxidation Catalysts and Air/Fuel Ratio Controllers on Lean Burn Engines Install Lean Burn Engines
As EPA commented on the Cumulative Effects Paper, it is unclear how the 4 Corners Task Force Interim Emissions Recommendations for Stationary RICE are being implemented. The mitigation option <u>Interim Emissions Recommendations for Stationary RICE</u> states that "BLM in New Mexico and Colorado are currently requiring these emission limits as a Condition of Approval (COA) for their Applications for Permits to Drill (APD). These limits currently apply only to new and **relocated** engines ... (compressors assigned to the well APD)..." However, we understand that BLM policy for a small engine COA as applied to an APD is for new and **replacement** engines. The Oil and Gas Workgroup should clarify how is the terms "relocated" and/or "replacement" are being defined by BLM and the USFS with respect to COAs for well located engines. For comparison, EPA's NSPS for spark ignition engines will apply to new, modified, and reconstructed units starting in January 2008. The terms new, modified, and reconstructed are defined in Federal Regulation.	Interim Emissions Recommendations for Stationary RICE
We recommend adding the following next generation technology to the four currently included in this mitigation option: Homogeneous-Charge Compression-Ignition (HCCI) technology was analyzed the by cumulative effects workgroup but was inadvertently omitted from the oil and gas work group mitigation option paper Next Generation RICE Stationary Technology. The following is a recommended text for inclusion in the Final Report: Homogeneous-Charge Compression-Ignition (HCCI) Engine I. Description of the mitigation option Overview Homogeneous charge compression ignition (HCCI) engines are under development at several laboratories. In these engines a fully mixed charge of air and fuel is compressed until the heat of compression ignites it. The HCCI combustion process is unique since it proceeds uniformly throughout the entire cylinder rather than having a discreet high-temperature flame front as is	Next Generation Stationary RICE Control Technologies – Cooperative Technology Partnerships

Comment	Mitigation Option
the case with spark ignition or diesel engines. The low-temperature combustion of HCCI produces extremely low levels of NOx. The challenge of HCCI is in achieving the correct ignition timing, although progress is being made in the laboratories.[1] Only a few experimental measurements of NOx from (HCCI) engines have been reported. The measurements are typically reported as a raw NOx meter measurement in parts per million rather than being converted to grams per horsepower-hour. Dibble reported a baseline measurement of 5 ppm when operated on natural gas.[2] Green reported NOx emissions from HCCI-like (not true HCCI) combustion of 0.25 g/hp-hr.[3] The achievable NOx emission levels are yet to be determined. It is not currently known if HCCI technology can be applied to all engine types and sizes. However, if all reciprocating engines could be converted to HCCI so that the engines produce no more than 0.25 g/hp-hr, then the overall NOx emissions reduction would be 80% in both Colorado and New Mexico using the calculation methodology of the SCR mitigation option. II. Description of how to implement A. Mandatory or voluntary It is too early to determine whether implementation of this technology will be voluntary or mandatory. B. Indicate the most appropriate agencies to implement III. Feasibility of the option A. Technical - HCCI is in the laboratory stage of development. B. Environmental - HCCI has the potential of extremely low NOx levels. C. Economic - HCCI is not sufficiently developed to have proven economic feasibility. IV. Background data and assumptions used 1. Bengt Johansson, "Homogeneous-Charge Compression-Ignition: The Future of IC Engines," Lund Institute of Technology at Lund University, undated manuscript. 2. Robert Dibble, et al, "Landfill Gas Fueled HCCI Demonstration System," CA CEC Grant No: PIR-02-003, Markel Engineering Inc. 3. Johney Green, Jr., "Novel Combustion Regimes for Higher Efficiency and Lower Emissions," Oak Ridge National Laboratory, "Brown Bag" Luncheon Series, December 16, 2002. V. Any uncertainty associated with the option (Low, Medium, or High) HCCI has high uncertainty.	

Comment	Mitigation Option
VI. Level of agreement within the work group for this mitigation option VII. Cross-over issues to the other source groups (Please describe the issue and which group.)	

Oil & Gas Overarching Issues Public Comments

Comment	Mitigation Option
The Four Corners Air Quality Task Force (4CAQTF) is a noble way of beginning communication between our citizenry and the polluting industries. Hopefully some meaningful "common ground" can be reached that will produce measurable air quality improvements. With a demonstrated failure of industry to "want to do their best" and when the "dollar gain" in a corporation's quarterly report is the measuring stick for it's shareholders, the recommendations from the 4CAQTF is up against a mature lobby force very capable of stopping meaningful actions that will lead to measurable benefits to our air quality! Therefore, spending serious time deliberating measurable benefits that could predictably occur if industry's suggestion of "year round" drilling EVERYWHERE as a means of ameliorating their emissions to me, seems without merit. A simple catalytic converter on each of their established fossil fuel operated engines would be considered a "wonderful start" of industry wanting "to do their best". Recommending to any state or federal land wildlife management agency to consider removing established seasonal habitat protection bans for the assumed benefit of distributing annual air quality pollutants should not be an option. Many years were spent by land management and wildlife management agencies formulating the habitats that need protection for identified species. The process to establish habitat closures is elaborate. Let us let this industry recommendation respectfully die and encourage installation of catalytic converters on industry's fossil fuel motors. This action does have measurable air quality results. As we drivers know, we are required by law to have catalytic converters on our vehicles as a way of demonstrating our contribution to improving air quality problems. As a recommendation, I would only suggest that if the oil and gas industry wants to recommend the lifting of this seasonal closure on identified lands, that THEY contact the state and federal agencies that have programming prerogatives over habitat and wildlife issues with their suggestion that lifting this ban would have beneficial measurable benefits for air quality concerns that outweigh wildlife concerns. The 4CAQTF should not be the "quarter back" for carrying the recommendation to state and federal habitat and wildlife agencies. I make these comments as a degreed wildlife biologist with 27 years of experience. Respectfully, Warren J. McNall 900 Sabena, Aztec, NM	Lease and Permit Incentives for Improving Air Quality on Public Lands

Comment	Mitigation Option
Disagree - unlike Wyoming, Colorado has a shortage of state and federal specialists to monitor impacts from oil and gas development. As a result, monitoring of oil and gas impacts to wildlife would likely not happen. Streamlining the permit process would be beneficial to operators economically, but may be at the expense of area wildlife and habitat.	Lease and Permit Incentives for Improving Air Quality on Public Lands
Regarding the paragraph: "Monitoring has also not been a model experience in this area. According to reports of a May, 2006, internal assessment Pinedale, Wyoming, Bureau of Land Management field office, the office neglected its commitment to monitor and limit harm to wildlife and air quality from natural gas drilling in western Wyoming. A wildlife biologist who worked in that Pinedale office, Steve Belinda, is reported to have quit his job because he and other wildlife specialists were required to spend nearly all their time in the office processing drilling requests and were not able to go into the field to monitor the effect of the thousands of wells on wildlife." Basically, I would suggest a more neutral approach than the quoted paragraph. It is rather forceful, without sufficient follow-up. It would help our situation if we could see whether the Farmington office is under similar pressures. Alternatively, examining the policies, rather than experiences, might make for a stronger position. For example, as the author seems to know a bit about BLM and permitting--she/he might instead look into the use of categorical exclusions (CAX) which are currently used to circumvent the environmental assessments (EA) that would normally be required to develop well fields on BLM land. (Sometimes this is also called streamlining.) How prevalent is this practice in the Four Corners, do CAX result in a lower standard of environmental review, and could this practice deleteriously impact 4C air quality?	Lease and Permit Incentives for Improving Air Quality on Public Lands
In light of the current global climate conditions, lessening our overall impact on the environment is everyone's duty to the planet and its children's future. This task force should not be in the position of negotiating away wildlife habitat in exchange for mitigating measures that ought to be a duty of the oil and gas industry as a cost of doing business on this planet.	Lease and Permit Incentives for Improving Air Quality on Public Lands
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Economic-Incentives Based Emission Trading System (EBETS)

Comment	Mitigation Option
Economic-incentives based emission trading systems (EBETS) have had varying levels of success nationally and have been less successful in geographic regions where pollutants are already causing harm to human health or the environment. It can also be argued that these systems lack incentives to improve environmental quality over economics. They can be more a function of market supply and demand driving the trades, not variations in regional human and environmental health "costs". Multisectoral trading systems are complex, increase challenges in emissions monitoring, and environmental justice considerations become more complicated due to inequitable concentrations of source emissions and different pollutant mixing outcomes. (Regarding the federal Acid Rain Program, indeed, the nationwide level of emissions from electric utilities were halved since 1980, however, no geographic restrictions were imposed and many areas of higher pollution levels remained at higher levels.) As stated in the Task Force document, the major burden for the EBETS mitigation option would be administrative; however the full burden must be assessed and coordinated among the state agencies. Not only would comparability and tracking of different types, sizes and ages of installations be extremely complicated, multi-pollutant emissions trading is challenging to monitor and enforce. Although it would be impossible to have an emissions trading system that eliminates environmental injustice, a carefully designed trading system that is rigorous, far-sighted, and includes geographic restrictions would have a much better chance of reducing localized injustices to human health and/or the environment.	Economic-Incentives Based Emission Trading System (EBETS)
The proposed incentive to modify standard stipulations for federal land if it is to be the relaxing or waiving of seasonal restrictions for wildlife while promoting year round drilling should not be a part of the voluntary program. Seasonal restrictions have been written to benefit wildlife during times of the year when they are at increased risk due to weather, nesting, birthing, etc. The Wyoming experience has shown the potential negative impacts of intense drilling on wildlife, and how highly wildlife is valued by a broad range of American people. With the pressures from the increase in drilling, wells, roads, and pipelines in the Four Corners area, we can ill afford to lose the wildlife protections from the stipulations that we currently have.	Voluntary Programs
New Mexico and Colorado already have rules governing H2S, no need to add more rules that may conflict.	Mitigation of Hydrogen Sulfide
New Mexico Environment Department does have controls for H2S on paper, but state environmental officials have validated that the state does not have H2S monitoring equipment.	Mitigation of Hydrogen Sulfide
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Mitigation of Hydrogen Sulfide
Rules that are capable of being enforced due to adequate staffing and necessary monitoring tools are what is needed to regulate this area. More rules that cloud the issue, or are effectively toothless due to lack of enforcement infrastructure will not accomplish the goals of this task force.	Mitigation of Hydrogen Sulfide

Power Plants

Power Plants: Preface

Overview

The Power Plants Work Group was charged with developing mitigation strategies for existing, proposed, and future power plants in the Four Corners area. For each strategy, one or more work group members provided a basic description of the strategy, ideas for implementation, and discussed feasibility issues to the extent possible.

Participation in the Power Plants Work Group included representatives from state, tribal and federal agencies; industry (including regional power plants); citizens; and interest groups. Ten to 20 participants attended each face-to-face meeting throughout the process. In total, the Power Plant Work Group brainstormed a total of 36 mitigation options and drafted 34. In addition, work group members helped in drafting 18 mitigation options for the Energy Efficiency, Renewable Energy and Conservation section.

Organization

The Power Plants work group initially collected information on existing emissions inventories and emissions projections for existing and proposed power plants. A spreadsheet, called Four Corners Area Power Plants Facility Data Table**,** is located at the end of the Power Plants section and was used as a tool to help supplement mitigation options papers with emissions reduction estimates. The work group divided the remainder of its work into the following categories.

Existing Power Plants: The work group first considered existing power plants, focusing on the two largest power plants in San Juan County: San Juan Generating Station (1800 MW) and Four Corners Power Plant (2000 MW). Eleven mitigation options were brainstormed and drafted for this section. The options drafted ranged from software applications and process optimization to retrofitting NOx and SO_2 emissions control technologies.

Proposed Power Plants: The work group next considered the proposed power plants category. The focus here was on the proposed Desert Rock Energy Project, a 1500 MW coal-fired power plant to be built in Burnham, 30 miles Southwest of Farmington. Options included funding of air quality improvement initiatives and consideration of the Integrated Gasification Combined Cycle (IGCC) process. Four of the 11 comments received on the Power Plants section of the Task Force Report during the public comment process were against building another power plant in the Four Corners area. Desert Rock also submitted comments on the Task Force report. Please see all the public comments pertaining to power plants in an appendix at the end of this section.

Future Power Plants: The work group discussed and documented eight strategies that future power plants could use to mitigate air pollution, including a carbon capture and sequestration (CCS) option, an option for clean coal incentives, large scale renewable energy production, and also an option on nuclear energy production.

Overarching Issues: Finally, the Power Plants report section also has an overarching category for options and ideas that may apply more broadly. Ten options were brainstormed and drafted here, and include mercury pollution mitigation and the Clean Air Mercury Rule (CAMR), cap and trade programs, greenhouse gas mitigation and one calling for a health study.

EXISTING POWER PLANTS: ADVANCED SOFTWARE APPLICATIONS

Mitigation Option: Lowering Air Emissions by Advanced Software Applications: Neural Net

I. Description of the mitigation option

There are many areas of power plant operation where Advanced Software Applications could lower air emissions from current levels. These processes range from the primary power generation equipment, to the various air pollution control devices (APCDs), such as scrubbers, precipitators, baghouses, and SCR units. The best gains in emission reduction couple state-of-the-art APCDs with advanced software applications operating within or in concert with the Distributed Control System, DCS. This mitigation option discusses Neural Network software to lower NO_x emissions at coal combustion low-NO_x burners. Other examples may be found in the Appendix.

Many power plant processes/devices, such as fan speeds, air damper positions, air and coal flows, are automatically controlled by the DCS. The DCS is a networked computer system with “distributed” input/output electronic hardware near the plant control devices, and “live” displays for the control room operators. Given the current state (on/off status or analog value) of every device tag in its database, the DCS uses feedback control algorithms to drive many controlled device variables. Set-points are optimized for the current desired mode of plant operation, such as satisfying a specified megawatt demand at the best possible heat rate.

Neural Networks offer advanced software control by “training” the software to “know” where outputs should be in relation to many inputs. Unlike traditional mathematical equation models, neural networks do not demand intimate understanding of the process. A neural network, sometimes referred to as “fuzzy logic,” is a type of “artificial intelligence” statistical computer program, which classifies large and complex data sets by grouping cases together in a manner similar to the human brain. Neural networks “learn” complex processes by analyzing their performance data.

San Juan Generation Station (SJGS) is currently working with a predictive neural network on Units 1 and 2 to lower NO_x emissions. This advanced software application, provided by the DCS vendor, minimizes NO_x formation by optimizing air flow to the burners (e.g., optimal flame temperature). SJGS is gaining experience with this type of software, anticipating the installation of state-of-the-art low-NO_x burner hardware. When these burners are installed on all units, increased reductions in NO_x are anticipated. Neural network software results in lower NO_x emissions than if the burners were controlled by standard DCS software alone.

The neural network uses inputs from the NO_x and O_2 CEMS, Carbon Monoxide (CO) emissions, burner air, secondary combustion air, coal flow, flame temperature, fan speeds, damper positions, etc. There could be dozens of inputs. The network is trained to identify the relative contribution of each process input to NO_x formation as measured by the CEMS. The network is trained across varying modes of plant operation – full load, partial load, startup, etc. at the lowest possible NO_x emissions. Then, as the generating unit operates in various modes, the neural network predictions refine the control actions the DCS would take on its own. This refinement lowered NO_x emissions by approximately 25% at an Entergy coal fired plant (Intech, July 2006 – “Netting a Model Predictive Combo”).
Note: CO_2 readings do not correlate significantly to NO_x control. Inputs from the NO_x, CO, and O_2 CEMS are used.

Benefits: NO_x reductions of 10% – 30%. Earn NOx Trading Credits as future regulations may require. Another important benefit is that tighter process controls from the neural network may improve the plant heat rate. When the heat rate improves, less energy is needed to maintain required MW load. With less associated stack gas volume for that load, all pollutant emissions decrease.

Trade-offs: Neural network cannot adapt to unforeseen upsets for which it was not originally trained. Neural net refinement control may have to be removed in these situations.

Some existing boiler controls may need to be automated so the neural network can act on them via the DCS. There are significant associated hardware, software, and labor costs. In combustion control schemes, optimizing NO_x for lowest emissions generally increases CO. CO emissions might increase because the neural network allows CO to ride very close to its regulatory limit. Without the network, CO is manually controlled to a lower level providing a cushion for upsets.

Software is processor-intensive.

Burdens: Cost of software application, more powerful computer hardware, "training" labor. Cost of upgrading some of the other controls on the boiler. The neural net is not much good unless it can actually adjust the equipment such as dampers, burner air registers, fan speed, etc. The controls have to be automated and have to be compatible with the neural net.

II. Description of how to implement

A. Mandatory or voluntary:

This option is being considered by San Juan Generating Station as part of consent decree to reduce NO_x emissions. It may be a viable option for FCPP. There may be some grants available to help fund such upgrades to existing power plants in Four Corners area.

FCPP has also installed neural networks and is gaining experience with process and emissions optimization. Desert Rock's potential use of this option is unknown.

B. Indicate the most appropriate agency(ies) to implement:

Federal, State, Tribal regulations should not specify specific control strategies, but rather impose emission limits reasonable for modern control strategies. Grandfathering of plants under NSR for installing enhanced controls, is another debate. However, if Federal NO_x budget trading is extended to this area under a Clear Skies option, the economic incentive of expensive NO_x trading credits to either buy or sell would encourage the final emissions control step of "advanced software applications" to realize optimum economic and environmental benefits.

Differing Opinion: Using NOx Budget trading and other grand fathering strategies do not address the pollution problems associated with old, out of date coal fired power plants. The Four Corners Power Plant is the top emitter of NOx in the Nation. Two coal fired power plants with high levels of emissions are located in the Four Corners. Grand fathering should not be an option. Extensive emissions clean up and control is necessary.

III. Feasibility of the option

A. Technical: Neural network technology is a viable control approach well established in many industrial process settings, but requires intensive computational capability. Powerful, cost-effective computers of recent years have facilitated growth of this technology. Due to some limitations to this control strategy, it takes its place with other advanced control strategies, such as Model Predictive Control.

B. Environmental: Environmental impacts are incidental, such as increased power consumption for more powerful computer hardware.

The point of this option is more efficient operation and thus lower emissions.

C. Economic: Software costs and labor are reasonable in light of the long term emission reductions attained. Generally, software costs are much less than capital expenditures for physical APCDs.

The Monitoring Work group asked if additional CEM or other technology be required to operate as part of the neural net feedback loop. SJGS and FCPP have existing NO_x CEMS to meet state and federal Acid Rain Program monitoring requirements. Acid Rain requires a high level of data quality assurance, including daily calibrations. A neural network continues to function upon loss of one or more inputs, within statistical limits. NO_x minimization control would continue during occasional loss of the NO_x CEMS input.

IV. Background data and assumptions used:
ISA Intech article
Information from San Juan Generating Station
There are many other sources of relevant information, including AWMA, Argonne, DOE.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups
Advanced Software Applications, including neural network control technology, could apply to sources in the Oil and Gas sector

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EXISTING: BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

Mitigation Option: Control Technology Options for Four Corners Power Plant

I. Description of the mitigation option

Summary of Option

Presumptive Best Available Retrofit Technology (BART) emission limits for SO_2 should be applied to all units at Four Corners Power Plant (FCPP). Presumptive BART emission limits for NO_x should be applied to Units 1, 2 and 3; and combustion controls and Selective Catalytic Reduction (SCR) on Units 4 and 5. When BART for PM10 at FCPP is analyzed, the regulatory authority and the facility should consider the control level achieved at San Juan Generating Station.

Background: Best Available Retrofit Technology (BART)

The Four Corners Power Plant consists of five pulverized coal fired boilers. Each boiler was built between 1962 and 1977 and emits more that 250 tons per year of visibility-impairing pollution. The units are therefore subject to the Best Available Retrofit Technology (BART) requirements under the Regional Haze Rule. The BART requirements mandate industrial facilities that cause or contribute to regional haze to control emissions of visibility-impairing pollutants. The Clean Air Act (CAA) states that BART guidelines shall apply to fossil-fueled fired generating power plants with a capacity greater than 750 MW (§169A(b)). The CAA does not exempt individual units of any size from BART requirements.

For Electric Generating Units with a capacity greater than 200 MW, the Environmental Protection Agency (EPA) has provided (rebuttable) presumptive emission limits for sulfur dioxide (SO_2) and nitrogen oxides (NO_x), based on boiler size, coal type and controls already in place. EPA "analysis indicates that these controls are likely to be among the most cost-effective controls available for any source subject to BART, and that they are likely to result in a significant degree of visibility improvement." (70 FR 39131, July 6, 2005). Because the two smaller units (#1 & #2, each at 190 gross MW) are subject to BART and are close in capacity to EPA's 200 MW threshold, the rationale for applying presumptive limits should hold for those units as well. Those presumptive limits (which are 30-day rolling averages) are:

- Unit #1 is 190 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #2 is 190 gross MW dry bottom wall -fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #3 is 253 gross MW dry bottom wall -fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #4 is 818 gross MW cell-burner: 0.15 lb SO_2/mmBtu and 0.45 lb NO_x/mmBtu
- Unit #5 is 818 gross MW cell-burner: 0.15 lb SO_2/mmBtu and 0.45 lb NO_x/mmBtu

Background: FCPP Emissions

In the 1980s, Arizona Public Service (APS) installed venturi scrubbers on Units 1-3, and early generation spray tower scrubbers—but with significant stack gas bypass—on Units 4 and 5. In 2003, APS began a program to further reduce SO_2 emissions at FCPP by eliminating most stack gas bypass. APS succeeded in bringing emissions down from a 30-day rolling plant wide average of 0.44 lb/mmBtu in 2003 to 0.16 lb/mmBtu by 2005, with further improvement to 0.14 lb/mmBtu; this represents a removal efficiency of 92 percent. Although NO_x and PM_{10} emissions were not addressed in that effort, NO_x emissions have been reduced slightly, but FCPP is still the largest emitter of NO_x among coal-fired power plants nationwide.[1] The current rate at which FCPP emits NO_x is approximately 0.54 lb/mmBtu.

The FCPP is located on the Navajo Reservation, and was previously regulated by emission limitations set by the State of New Mexico. The Tribal Authority Rule, however, generally stated that state air quality regulations could not be enforced against facilities on the Indian reservation. EPA, therefore, has to issue federally enforceable emission limitations for FCPP. On August 31, 2006 EPA Region 9 proposed a Federal Implementation Plan (FIP) to establish federally enforceable emission limits for SO_2, NO_x, total PM, and opacity. The proposed FIP would require 88 percent removal of plant wide SO_2[2] on an annual rolling average basis. This would result in plant wide annual average SO_2 emissions being limited to 0.24 lb/mmBtu on coal projected to be burned in 2016.[3] The proposed FIP would require NO_x emissions not to exceed 0.85 lbs/mmBtu for Units 1 and 2, and 0.65 lbs/mmBtu for Units 3, 4 and 5.

The Four Corners Power Plant is located on the Navajo Reservation and the Tribal Authority Rule has stated that state air quality regulations could not be enforced against facilities on the Indian Reservation. It is imperative that a firm agreement between the Navajo Tribe and the Federal EPA be negotiated to guarantee that the Federal EPA will be the regulatory and enforcement agency for the Four Corners Power Plant (FCPP) clean up process. This will allow the Federal EPA to regulate and enforce emission limits for SO2, NOx, PMs and opacity that are specified in the new EPA Region 9 FIP.

Update: On April 30, 2007, EPA Region 9 finalized a Federal Implementation Plan (FIP) that establishes federally enforceable emission limits for SO_2, NO_x, total PM_{10} and opacity. The FIP requires 88 percent removal of plant wide SO_2 on an annual rolling average basis, and limits three-hour average SO_2 emissions to 17,900 lbs/hr plant wide. This would result in plant wide annual average SO_2 emissions being limited to 0.24 lb/mmBtu on coal projected to be burned in 2016. The FIP requires that 30-day rolling average NO_x emissions are not to exceed 0.85 lbs/mmBtu for Units 1 and 2, and 0.65 lbs/mmBtu for Units 3, 4 and 5; and daily NO_x emissions are not to exceed 335,000 lbs. PM emissions are limited to 0.050 lbs/mmBtu, and opacity is limited to 20%, except for one six-minute period per hour not to exceed 27%.

Presumptive BART at FCPP

Sulfur Dioxide

The application of presumptive BART limits for SO_2 on Units 1-5 at FCPP would result in a plant wide annual average of 0.15 lbs/mmBtu or 93 percent removal based on future coal. Estimated emissions for 2018[4] are shown in Figures 2 & 3 for emissions at the current level of control, the proposed level of control under the FIP, a scenario with BART applied to Units 3-5 only, and BART applied to Units 1-5. All options assume control efficiency remain constant within each given scenario.

Emissions under the scenario where presumptive BART for SO_2 is applied to all Units are only slightly less than current emission rates. However, applying presumptive BART for SO_2 would result in an emission limit specified as an allowable rate of emissions (lbs/mmBtu). The FIP would allow SO_2 removal to decline from the present 92 percent to 88 percent. Additionally, the FIP specifies the SO_2 limit in terms of efficiency, or percent removal of SO_2 from the coal being burned. If the coal quality decreases (to higher sulfur coal), as it is projected to do, the limit in terms of percent removal will allow for more emissions of SO_2; thus, it is preferable to have an emission rate as the controlling limit.

Nitrogen Oxides

The application of presumptive BART limits for NO_x on Units 1-3 (0.23 lb/mmBtu), and combustion controls and SCR on Units 4 & 5 would result in a plant wide annual average of 0.16 lb/mmBtu. Application of presumptive BART for Units 4 & 5 would result in a rate of 0.45 lbs/mmBtu for those Units. Estimated emissions for 2018 are shown in Figure 4 for emissions at the current level of control, the current Title V permit limit, the proposed level under the FIP, a scenario with BART applied to Units 1-5, and a scenario that applies BART to Units 1-3 and applies combustion controls and SCR to Units 4 & 5. NO_x emissions under the proposed FIP would be significantly higher than current rates; application of presumptive BART for NO_x to all Units would reduce NO_x 30 percent from current rates; application of presumptive BART to Units 1-3, and combustion controls plus SCR on Units 4 & 5 would result in the most significant reductions of NO_x: 70 percent from current rates, and less than half from the scenario with BART on all Units.

Since Units 4 and 5 are cell burners, they are inherently very high emitters of NO_x, and, because of the narrowness of their furnaces, are very difficult to reduce emissions by combustion controls alone (combustion controls alone represent presumptive BART). EPA has recognized that the presumptive limits (and associated technologies) do not preclude the application of different technologies: "[b]ecause of differences in individual boilers, however, there may be situations where the use of such controls would not be technically feasible and/or cost-effective. . . . Our presumption accordingly may not be appropriate for all sources."[5] The cost (see below) of SCR on these Units is comparable to combustion controls—which may not be technically feasible—and SCR will result in significantly more reductions of NO_x. Currently, Units 4 and 5 each emit twice the NO_x as Units 1, 2 and 3 individually.[6] Therefore, SCR is the best reasonable method to achieve meaningful NO_x reductions at Units 4 and 5.

Reduction of NO_x is particularly important to improve visibility at Mesa Verde National Park, which is 52 km away from FCPP. As shown in Figures 1a, 1b and 1c, visibility has degraded at Mesa Verde over the past decade, and the portion of degradation due to nitrate has increased (while there has been no trend in degradation due to sulfate).

II. Description of how to implement

A. Mandatory or voluntary:

This option represents a mandatory, federally enforceable emission limit.

B. Indicate the most appropriate agency(ies) to implement:

The regulating agency for this facility is EPA Region 9.

III. Feasibility of the option

FCPP is currently at or below the presumptive BART limit for SO_2. No additional controls are needed.
Differing Opinion: FCPP does not consistently operate at or below presumptive BART limit for SO_2

For Units 1-3, the Environmental Protection Agency's suggested presumptive BART for NO_x limits "reflect highly cost-effective technologies."[7] EPA, in fact, performed visibility impact and cost-effectiveness analyses on the presumptive limits. Therefore, the BART presumptive limits of NO_x are considered to be technical and economically feasible.

EPA states that the majority of units could meet presumptive NO_x limits with current combustion control technology for between \$100 and \$1000 per ton of NO_x removed. If more advanced combustion controls are required, the cost would be less than \$1500 per ton of NO_x removed. Furthermore, EPA states that "by the time units are required to comply with any BART requirements . . . more refinements in combustion control technologies will likely have been developed by that time. As a result, we believe our analysis and conclusions regarding NO_x limits are conservative.[8]

Application of EPA's Cost Tool model for Units 4 & 5 predicts that NO_x could be reduced by 70% to the levels shown by application of combustion controls plus SCR at a cost of \$409 - \$464 per ton of NO_x removed.[9] EPA states that the average cost of combustion controls on cell burners (presumptive BART) is \$1021 per ton. The average cost of applying SCR to cyclone units, (which for those units is presumptive BART), is \$900 per ton.

IV. Background data and assumptions used

Historical emissions data comes from EPA's Clean Air Markets Division databases. Projected capacity utilizations come from the Western Regional Air Partnership's "11_state_EGU_analysis" projections.

EPA's cost tool: http://www.epa.gov/airmarkt/arp/nox/controltech.html

V. Any uncertainty associated with the option

Uncertainties in FCPP's ability to meet the BART presumptive limit for SO_2 include future coal quality. Future emissions of SO_2, NO_x and PM10 will depend on future utilization, which at this point has been predicted.

VI. Level of agreement within the work group for this mitigation option To Be Determined.

VII. Cross-over issues to the other Task Force work groups None.

Citations:

[1] http://cfpub.epa.gov/gdm/index.cfm?fuseaction=factstrends.top_bypollutant

[2] Although EPA limits annual average SO_2 emissions to 12.0% of the SO_2 produced by the plant's coal-burning equipment, its method of calculating the amount of SO_2 produced is not consistent with EPA's "Compilation of Air Pollutant Emission Factors," (AP-42) which assumes that 12.5% of the sulfur in sub-bituminous coal (as burned at FCPP) is never converted to SO_2 but is retained in the ash collected in the boiler. When this sulfur retention is taken into consideration, the EPA proposal represents 86% control of potential SO_2 emissions.

[3] BHP, the supplier of coal to FCPP, has projected coal quality to 2016 when its contract expires. This estimate is based upon 2016 coal with a heating value of 8,890 Btu/lb and a sulfur content of 0.85%. (document prepared by C. Nelson, BHP Navajo Coal Company on 27 February 2006 and submitted by Sithe Global as part of the Desert Rock permit application).

[4] All projections are based upon fuel quality estimates from the coal supplier and WRAP utilization growth projections.

[5] 70 F.R. 39134 (July 6, 2005).

[6] http://www.epa.gov/airmarkets/emissions/prelimarp/05q4/054_nm.txt

[7] 70 F.R. 39131, July 6, 2005.

[8] 70 F.R. 39135, July 6, 2005.

[9] http://www.epa.gov/airmarkt/arp/nox/controltech.html

Figure 1.a. WRAP Total Extinction Trends

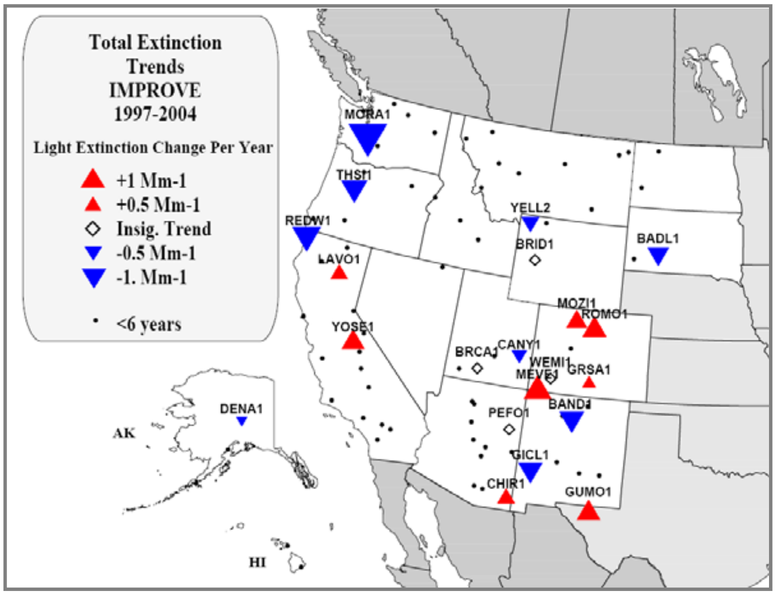


Figure 1.b. WRAP Sulfate Extinction Trends

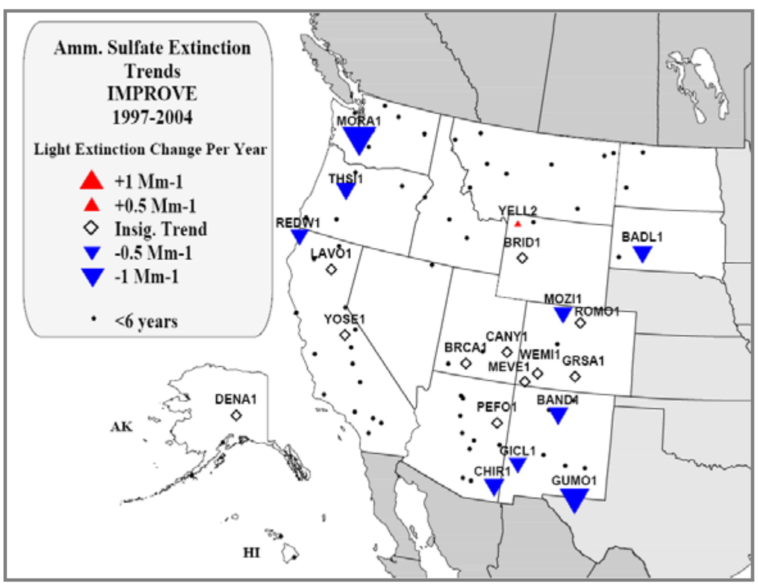


Figure 1.c. WRAP Nitrate Extinction Trends

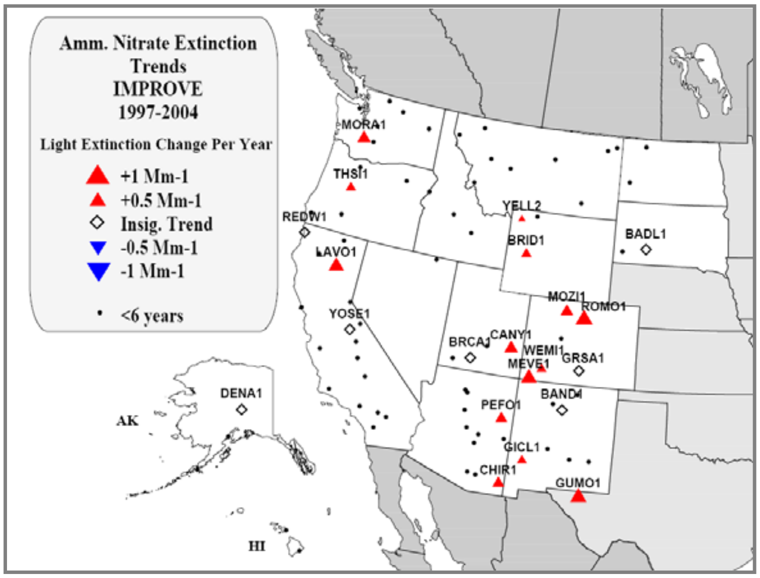


Figure 2. FCPP Emission Trends

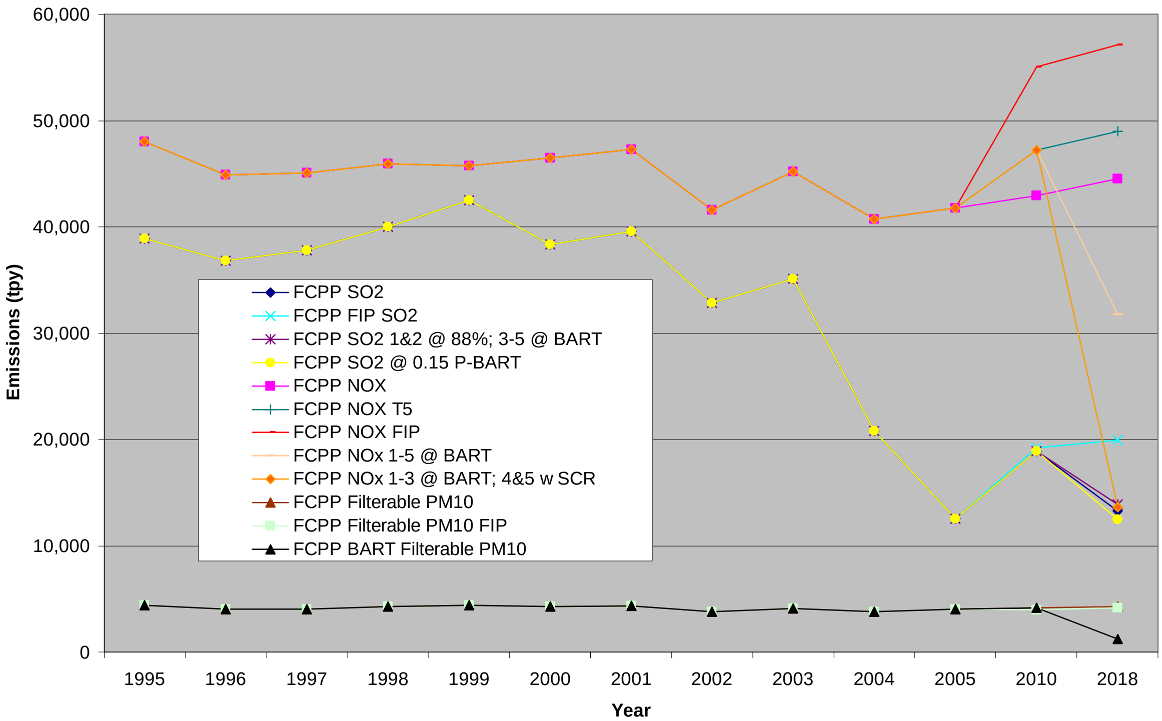


Figure 3. FCPP 2018 SO2 vs. Control Strategy

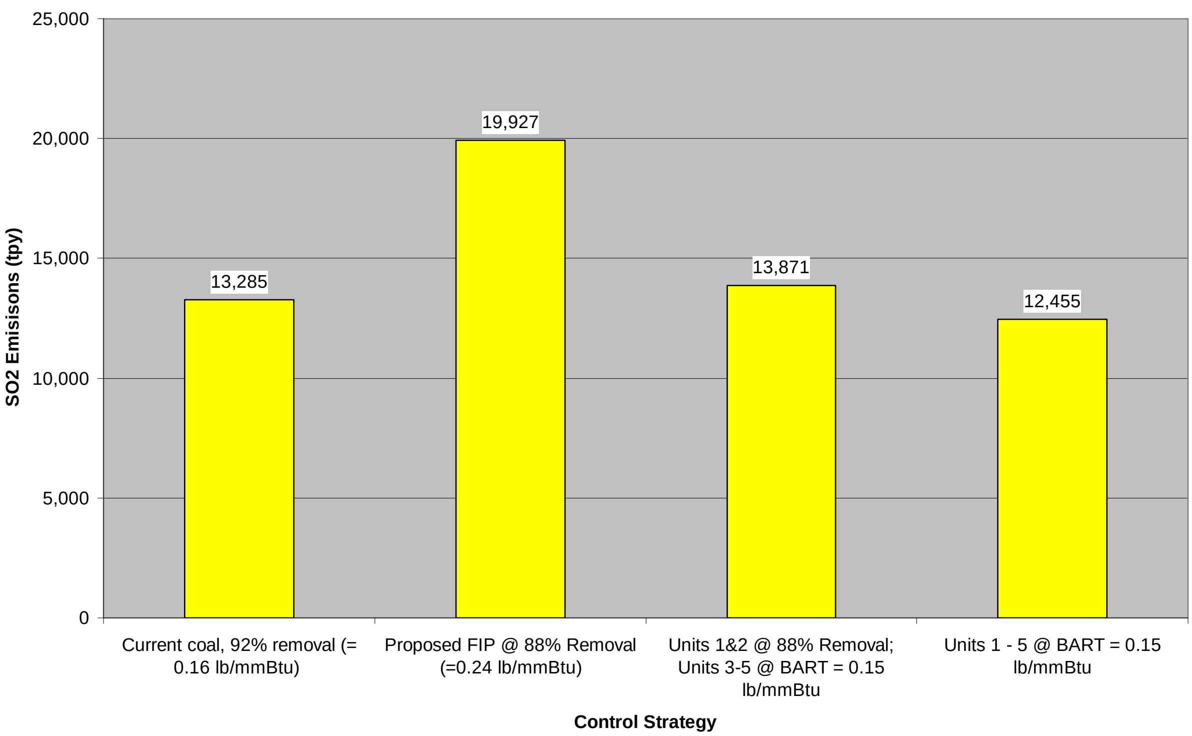
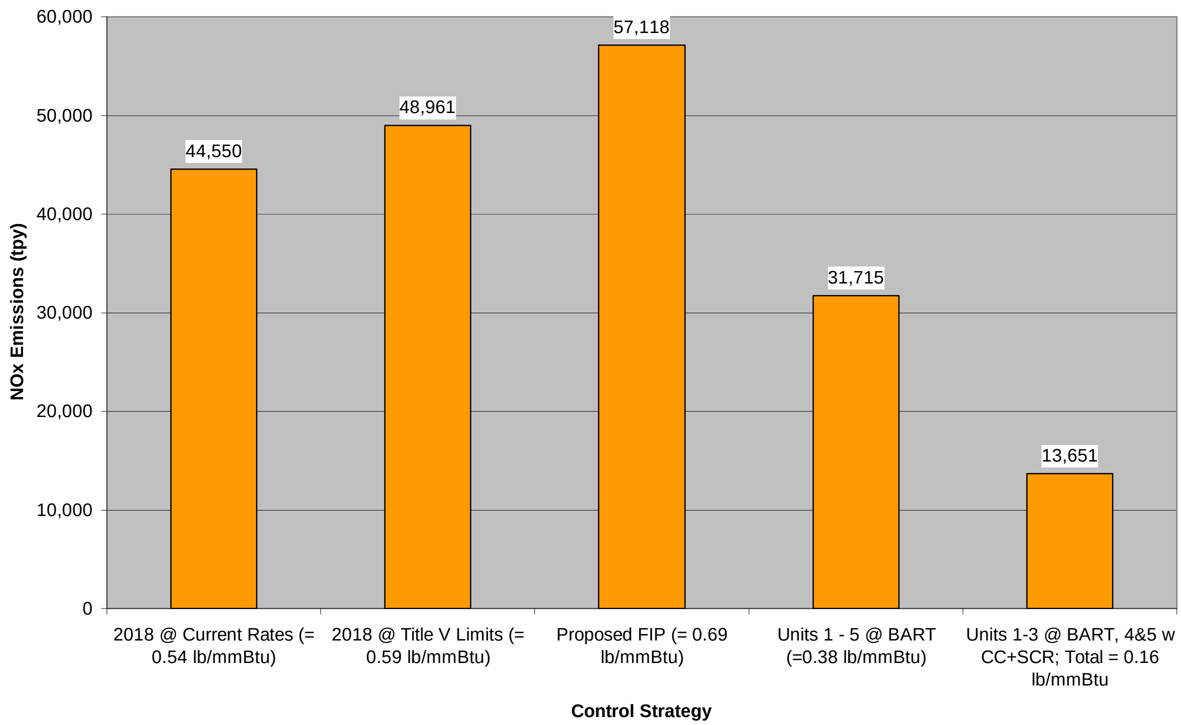


Figure 4. FCPP 2018 NOx Emissions vs Control Strategy



Mitigation Option: Control Technology Options for San Juan Generating Station

I. Description of the mitigation option

Summary of Option

Presumptive emission limits for NO_x should be applied to all units at San Juan Generating Station (SJGS).

Background: Best Available Retrofit Technology (BART)

SGJS consists of four pulverized coal fired boilers. Each boiler was built between 1962 and 1977 and emits more that 250 tons per year of visibility-impairing pollution. The units are therefore subject to the Best Available Retrofit Technology (BART) requirements under the Regional Haze Rule. The BART requirements mandate industrial facilities that cause or contribute to regional haze to control emissions of visibility-impairing pollutants. The Clean Air Act (CAA) states that BART guidelines shall apply to fossil-fueled fired generating power plants with a capacity greater than 750 MW (§169A(b)). The CAA does not exempt individual units of any size from BART requirements.

For Electric Generating Units with a capacity greater than 200 MW, the Environmental Protection Agency (EPA) has provided (rebuttable) presumptive emission limits for sulfur dioxide (SO_2) and nitrogen oxides (NO_x), based on boiler size, coal type and controls already in place. EPA "analysis indicates that these controls are likely to be among the most cost-effective controls available for any source subject to BART, and that they are likely to result in a significant degree of visibility improvement." (70 FR 39131, July 6, 2005). Those presumptive limits (which are 30-day rolling averages) are:

- Unit #1 is 359 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #2 is 359 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #3 is 555 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #4 is 555 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu

Background: SJGS Emissions

In March of 2005, Public Service of New Mexico (PSNM) entered into a Consent Decree to reduce SO_2, NO_x, and PM_{10} emissions by 2010 at SGJS to the levels shown below:

- NO_x = 0.30 lb/mmBtu (30-day rolling average). The Consent Decree requires that San Juan minimize NOx emissions. The 0.30 lb/mmBtu limit will be evaluated after 1 year of operation and adjusted to a lower limit if possible.
- SO_2 = 90% annual average control,[1] not to exceed 0.250 lb/mmBtu for a seven-day block average.
- PM_{10} = 0.015 lb/mmBtu (filterable)

PSNM will replace all four existing Electrostatic Precipitators with Fabric Filters. San Juan currently meets the 0.015 lb/mmBtu limit with the existing Electrostatic Precipitators. The fabric filters (baghouses) will be installed primarily to reduce opacity spikes during upset conditions and to allow the addition of activated carbon for mercury control.

PSNM will have to meet the 90% SO_2 control requirement regardless of the coal quality. Current coal quality averages about 1.4 lb SO_2/mmBtu (uncontrolled). Therefore, ninety percent control would result in an annual average emission rate of 0.14 lb/mmBtu, and would likely satisfy the presumptive BART requirement.

Presumptive BART for NO_x at SJGS

The Consent Decree (CD) level for NO_x is 0.30 lb/mmBtu; the BART presumptive level for NOx is 0.23 lb NO_x/mmBtu. The BART presumptive level is lower than that in the CD, and therefore will result in lower emissions. Figure 1 depicts the historical trends of SO_2 and NO_x at SJGS, as well as future trends out to 2018 based upon available information on coal quality[2] and capacity utilization.[3] Emission increases after 2010 are due to increased utilization. The decreased NO_x emissions are based on the assumption that SJGS Units 1-4 will meet the presumptive BART limit for NO_x by 2018.

The presumptive BART level of 0.23 lbs/mmBtu was developed based on Powder River Basin (PRB) Coal. Although both the PRB and the San Juan Basin coals are considered sub bituminous, San Juan coal has properties of bituminous coal which has a higher presumptive BART level.

Reduction of NO_x is particularly important to improve visibility at Mesa Verde National Park, which is 43 km away from SJGS. As shown in Figures 1a, 1b and 1c, visibility has degraded at Mesa Verde over the past decade, and the portion of degradation due to nitrate has increased (while there has been no trend in degradation due to sulfate).

II. Description of how to implement

A. Mandatory or voluntary:

This option represents a mandatory, federally enforceable emission limit.

B. Indicate the most appropriate agency(ies) to implement:

The regulating agency for this facility is the State of New Mexico.

III. Feasibility of the option

The Environmental Protection Agency's suggested presumptive BART limits "reflect highly cost-effective technologies."[4] EPA, in fact, performed visibility impact and cost-effectiveness analyses on the presumptive limits. Therefore, the BART presumptive limits of NO_x are considered to be technical and economically feasible.

EPA states that the majority of units could meet these NO_x limits with current combustion control technology for between \$100 and \$1000 per ton of NO_x removed. If more advanced combustion controls are required, the cost would be less than \$1500 per ton of NO_x removed. Furthermore, EPA states that "by the time units are required to comply with any BART requirements . . . more refinements in combustion control technologies will likely have been developed by that time. As a result, we believe our analysis and conclusions regarding NO_x limits are conservative.[5]

The most accurate cost estimate for SJGS to meet the BART limit for NO_x is likely to be from EPA's Cost Tool model, which estimates costs for specific units at specific emission rates.[6] That model predicts that the presumptive BART limits for NO_x could be met at costs of \$355 - \$501 per ton.

San Juan is currently in the process of doing a BART Analysis. It will be submitted to the NMED in June 2007.

IV. Background data and assumptions used

Historical emissions data comes from EPA's Clean Air Markets Division databases. Projected capacity utilizations come from the Western Regional Air Partnership's "11 State EGU Analysis" projections.
EPA's Cost Tool Model: http://www.epa.gov/airmarkt/arp/nox/controltech.html

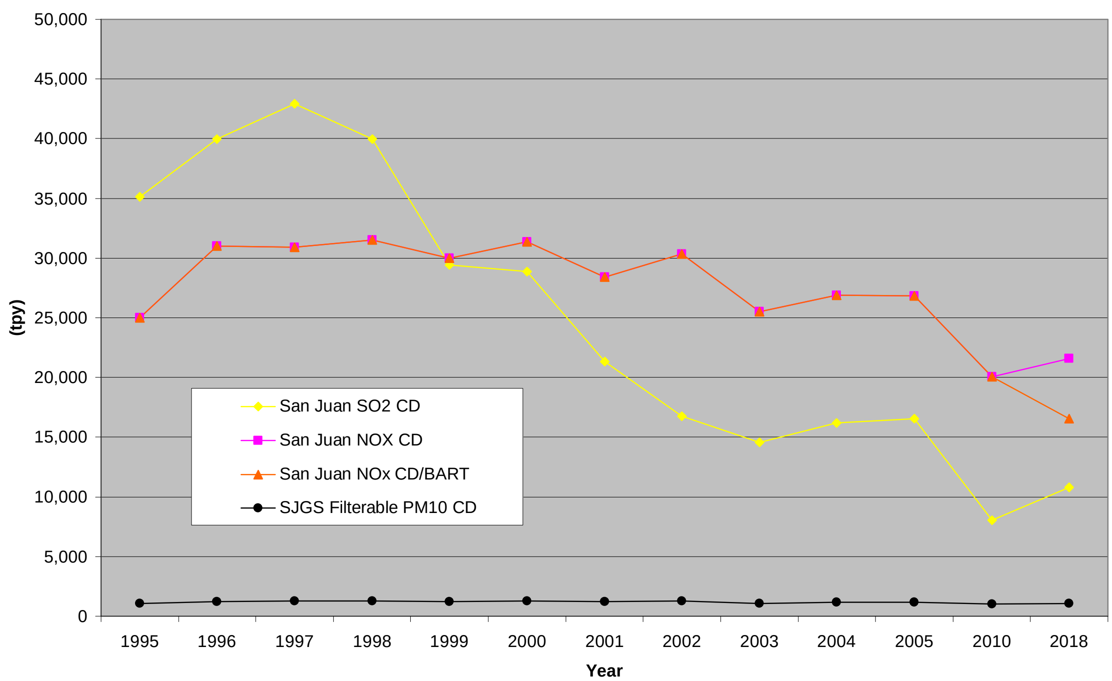
V. Any uncertainty associated with the option (Low, Medium, High)
Uncertainties in SJGS's ability to meet the BART presumptive limit for SO2 include future coal quality. Future emissions of SO_2, NO_x and PM10 will depend on future utilization, which at this point has been predicted.

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups None.

Citations:
[1] Based upon scrubber inlet and outlet SO_2 concentrations, as measured by Continuous Emission Monitors.
[2] Document prepared by C. Nelson, BHP Navajo Coal Company on Feb. 27, 2006 and submitted by Sithe Global as part of the Desert Rock permit application.
[3] Western Regional Air Partnership, 11 State EGU Analysis spreadsheet
[4] 70 F.R. 39131, July 6, 2005.
[5] 70 F.R. 39135, July 6, 2005.
[6] http://www.epa.gov/airmarkt/arp/nox/controltech.html

Figure 1. San Juan SO2 & NOx



EXISTING: OPTIMIZATION

Mitigation Option: Energy Efficiency Improvements

I. Description of the mitigation option

Upgrades or major repairs to existing power plants are potentially subject to the New Source Review process. This includes projects that are undertaken to improve the efficiency of the plants (i.e., produce more power while burning less or the same amount of fuel.) This process has been so difficult and cumbersome that these projects are often not cost-effective to pursue. The regulatory agencies should work closely with the utilities to simplify the process, remove barriers and to encourage these efficiency improvements.

II. Description of how to implement

A. Mandatory or voluntary:

B. Indicate the most appropriate agency(ies) to implement

Regulating agencies:

EPA Region 9 Air Programs, Navajo Nation EPA, New Mexico Air Quality Bureau

III. Feasibility of the option

A. Technical:

B. Environmental:

C. Economic:

IV. Background data and assumptions used:

V. Any uncertainty associated with the option (Low, Medium, High):

Medium

VI. Level of agreement within the work group for this mitigation option.

TBD

VII. Cross-over issues to the other Task Force work groups:

None

Mitigation Option: Enhanced SO_2 Scrubbing

I. Description of the mitigation option

Enhanced SO_2 scrubbing on existing power plants in the Four Corners area has resulted in significant SO_2 reductions. This mitigation option suggests further efforts to develop and optimize SO_2 scrubbing at San Juan Generating Station and Four Corners Power Plant.

Background:
Wet Flue-Gas Desulfurization System:
Wet scrubbing, or wet flue gas desulfurization (FGD), is the most frequently used technology for post-combustion control of SO_2 emissions. It is commonly based on low-cost lime-limestone in the form of aqueous slurry. Lime is calcium oxide, CaO; Limestone is $CaCO_3$. The slurry brought into contact with the flue-gas absorbs the SO_2 in it. $CaSO_4$-$2H_2O$, Gypsum, is formed as a byproduct (1).

Gas flow per unit cross sectional area, which determines scrubber diameter, must be low enough to minimize entrainment. Mass transfer characteristics of the system determine absorber height. These vessels and the accompanying equipment used for slurry recycle, gypsum dewatering, and product conveyance tend to be quite large. Some variations of this technology produce high quality gypsum for sale. Less pure waste product may be sold for use in cement production. If neither of these options is practiced, the scrubber waste must be disposed of in a sludge pond or similar facility (2).

The wet scrubber has the advantage of high SO_2 removal efficiencies, good reliability, and low flue gas energy requirements (1).

What is being done:
San Juan Generating Station has initiated an Environmental Improvement program under its consent decree that includes enhanced SO_2 scrubbing. Projections show that optimization of SO_2 scrubbing will result in a reduction of SO_2 from the current emission rate of 16,569.5 tons/yr to an emissions rate of 8,900 tons/yr by the year 2010 (3, 4, 5). This would translate as an increase in SO_2 removal efficiency from 81% to 90% as required by the consent decree.

The Consent Decree that San Juan has entered into will require a minimum of 90% removal of SO2.

Four Corners Power Plant has also made significant improvements in SO_2 emissions control efficiency. APS, in partnership with the Navajo Nation, several environmental groups and federal agencies, conducted a test program to determine if the efficiency of the existing scrubbers at Four Corners Power Plant could be improved from the recent historical level of 72% SO_2 removal to 85%. The test program, which was completed in spring of 2005, was successful and the plant was able to achieve a plant-wide annual SO_2 removal of 88%. In fact, data indicates that a 92% removal, or 0.16 lbs/mmBtu SO2 limit was achieved. Some parties involved in the test program have agreed that a new rule should propose to require 88% removal efficiency for the Four Corners Power Plant (6). Parties are also interested, however, in a mass emissions limit as opposed to removal rate to protect against air quality degradation from higher sulfur coal.

The way "removal" is used here is based on including the amount of sulfur retained in the ash. For FCPP, this amounts to about 2% "bump-up" of the control efficiency. So, 88% removal is the equivalent of 86% control. By contrast, both the NM regulations and the SJGS consent decree require that the control efficiency across the scrubber be measured by CEMs before and after the scrubber.

72% SO_2 removal resulted in approximately 22,450 Tons/yr SO_2 emissions. The new emissions control removal efficiency of 88% translated to 12,500 Tons/yr SO2 emissions in 2005.

Further advances in SO_2 scrubber optimization should be explored and implemented as they become available. It may be possible to achieve over 90% SO_2 removal efficiencies with enhanced SO_2 scrubbing on existing power plants in the 4C area

During 2005, FCPP demonstrated that it can achieve better than 90% control of SO_2.

Benefits: SO_2 removal increase. Possible co-benefits are increased particulate removal, and also mercury removal.
Tradeoffs:
Burdens: Cost to existing power plants including: optimization controls or additional retrofit technologies.

II. Description of how to implement
A. Mandatory or voluntary
Voluntary emissions reductions that are above and beyond new standards

Differing Opinion: A FCPP FIP that reflects the capabilities of the control equipment and coal supply

B. Indicate the most appropriate agency(ies) to implement
New Mexico Air Quality Bureau
EPA Region 9 and Navajo Nation EPA

III. Feasibility of the option
A. Technical: technology is available and feasible.
B. Environmental: Optimized SO2 scrubbing could result in SO_2 control efficiency above 90%.
C. Economic: Improving existing emissions control process through optimization is often less expensive than retrofitting plant with entirely new emissions control equipment.

IV. Background data and assumptions used:
1. El-Wakil, M.M. Power Plant Technology; McGraw-Hill, New York: 2002.
2. Clean Coal Technology Topical Report #13, May 1999, DOE, "Technologies for the combined Control of Sulfur Dioxides and Nitrogen Oxides from Coal-fired Boilers"
3. Current estimated SO_2 emissions from Four Corners area power plants (4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV9)
4. San Juan Generating Station (SJGS) presentation for 4CAQTF, August 9, 2006, "SJGS Emissions Control Current and Future"
5. Clean Air Markets – Data and Maps – 2005 Unit Emissions Report – Emissions for San Juan Generating Station & Four Corners Steam Electric Station
6. Final rule for Four Corners Power Plant:
ENVIRONMENTAL PROTECTION AGENCY, 40 CFR Part 49, [EPA-R09-OAR-2006-0184; FRL-], Source-Specific Federal Implementation Plan for Four Corners Power Plant; Navajo Nation

V. Any uncertainty associated with the option
Medium – SO_2 scrubbing control efficiencies have increased recently. Optimization of SO_2 scrubbing systems have limitations.

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups None

EXISTING: ADVANCED NO_x CONTROL TECHNOLOGIES

Mitigation Option: Selective Catalytic Reduction (SCR) NO_x Control Retrofit

I. Description of the mitigation option,
To reduce NOx emissions from the existing power plants in the Four Corners area, a Selective Catalytic Reduction system could be retrofitted to San Juan Generating Station and Four Corners Power Plant.

Selective Catalytic Reduction, SCR, uses ammonia or urea along with catalysts in a post-combustion vessel to transform NO_x into nitrogen and water. It can achieve the 0.15-pound-per-million Btu standard (1).

Some eastern EGUs retrofitted with SCR have achieved 0.05 lb/mmBtu. Based on recent permit applications and boilers in the east that have retrofitted with SCR, this technology can typically achieve a 90 percent reduction in NO_x emissions.

Ammonia is used as the reducing agent. It is injected into the flue gas stream and then passes over a catalyst. The ammonia reacts with nitrogen oxides and oxygen to form nitrogen and water.

The main Selective Catalytic Reduction reaction is $4NH_3 + 4NO + O_2 \rightarrow 4\ N_2 + 6H_20$ (2)

Supplemental description of Selective Catalytic Reduction available from US EPA, AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01) (for Desert Rock Energy Facility)

This report further discusses technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging or poisoning, ammonia slip emissions, and design of the ammonia injection system (3).

And the SCR system
The SCR system is comprised of a number of subsystems. These include the SCR reactor and flues, ammonia injection system and ammonia storage and delivery system (3).

Based on heat input and emissions data from the Acid Rain Program:
Currently NO_x emissions from San Juan Generating Station are on the order of 0.42 lbs/mmBtu or 26,800 Tons/yr.
Currently NOx emissions from the Four Corners Power Plant are approximately 0.57 lbs/mmBtu or 40,700 Tons/yr (4). Note: FCPP is the largest NOx-emitting EGU is the US.

The proposed Desert Rock Energy facility is planning to build their facility with Selective Catalytic Reduction technology to control NO_x emissions. They expect 85-90% control of NOx. The permit allowed NOx emissions will be 0.060 lbs/mmBtu fuel input (2).

Retrofitting a Selective Catalytic Reduction to existing power plants would be much more difficult than installing equipment with the construction of the plant; however, it is an option to greatly reduce NOx emissions from existing sources. It may be able to reduce emissions from existing sources by as much as 50%.

Differing Opinion: Applying SCR to existing plants may be more difficult than new installation; it is not a given. SCR has been successfully applied in the East in response to the CAIR rule. Retrofits at eastern utilities subject to the NOx SIP Call and CAIR typically set a 90% reduction goal. The vintage EPA Cost Tool database assumes 70% control by SCR, and SCR has improved dramatically since then.

Benefits: It is an option to greatly reduce NOx emissions from existing sources. It may be able to reduce emissions from existing sources by as much as 50% - 90%+. SCR may have some co-benefit reductions of Mercury emissions.

Tradeoffs:
Ammonia that is not reacted will “slip” through into exhaust. Ammonium salts could also form thus increasing loading to the particulate collection stage as PM10 (and PM2.5) (2). This is less likely with lower sulfur coal.
SCR tends to increase the reaction of SO_2 to SO_3 and increases the formation of acid mists. This could require additional treatment of the flue gas. This is less likely with lower sulfur coal.

Any analysis should compare the cost of SCR to the costs of combustion controls.

Application of EPA’s Cost Tool model for the Four Corners Power Plant, Units 4 & 5 predicts that NO_x could be reduced by 70 percent to the levels shown by application of combustion controls plus SCR at a cost of \$409 - \$464 per ton of NO_x removed. EPA states that the average cost of combustion controls on cell burners (presumptive BART) is \$1021 per ton. The average cost of applying SCR to cyclone units, (which for those units is presumptive BART), is \$900 per ton.

Burdens: Retrofit costs to existing power plants. Installation may be cost prohibitive for some existing plants because of the physical layout of the plant. Safety issue with handling of ammonia for use as reducing agent

II. Description of how to implement

A. Mandatory or voluntary
Retrofit program could be mandatory or voluntary
SCR application could be considered in the context of BART.

B. Indicate the most appropriate agency(ies) to implement
State Air Quality Bureaus, Federal EPA, Industry

III. Feasibility of the option

A. Technical – commercially available

B. Environmental – high reduction efficiencies demonstrated 85-90+%.
Sulfur content of the coal is an important factor in use of SCR. The low-sulfur coals burned in the 4 Corners area should be more compatible with SCR. SCR is being widely applied to a variety of bituminous and sub-bitumninous coals, especially in the East. Requiring catalyst replacement is an economic issue.

The SCR process is subject to catalyst deactivation over time (2).

C. Economic – Retrofit costs. Additional maintenance costs

*Cumulative Effects Work Group – How would 50%-90% emissions reductions from the two existing power plants affect visibility and ozone?
*Monitoring Work Group – Would it be possible to measure ammonia slip in the exhaust gases?

IV. Background data and assumptions used

1. US Department of Energy (DOE) Pollution Control Innovations Program
http://www.fossil.energy.gov/programs/powersystems/pollutioncontrols/index.html

2. Development of Nitric Oxide Catalysts for the Fast SCR Reaction, Matt Crocker, Center for Applied Energy Research, University of Kentucky (2005)

3. US EPA, AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01) (for Desert Rock Energy Facility)
*A good description of Selective Catalytic Reduction is available on pp.9-10 of the US EPA, Ambient Air Quality Impact Report, Best Available Control Technology discussion, for the Desert Rock Energy Facility.

4. Clean Air Markets – Data and Maps – 2005 Unit Emissions Report – Emissions for San Juan Generating Station & Four Corners Steam Electric Station
Heat input for all 4 units at San Juan Generation Station 127,629,979 mmBtu in 2005.
Heat input for all 5 units combined at 4Corners Power Plant 141,394,388 mmBtu in 2005.

5. San Juan Generating Station (SJGS) presentation for 4CAQTF, August 9, 2006, "SJGS Emissions Control Current and Future"

V. Any uncertainty associated with the option High.

Differing Opinion: The success of SCR in reducing NO_x emissions is a proven technology

VI. Level of agreement within the work group for this mitigation option To Be Determined.

VII. Cross-over issues to the other Task Force work groups

Oil & Gas industry may also look at SCR as a method to reduce natural gas compressor NO_x emissions

Mitigation Option: BOC LoTOx™ System for the Control of NOx Emissions

I. Description of Mitigation Option

Belco BOC LoTox is an oxidation technology for flue gas NOx control. It was developed in recent years and has become commercially successful and economically viable as an alternative to ammonia and urea based technologies. Older commercial technologies such as Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR), which reduce NOx to nitrogen using ammonia or urea as an active chemical, are limited in their use for high particulate and sulfur containing NOx streams such as from coal-fired combustors, or are unable to achieve sufficient NOx removal to meet new NOx regulation levels. In contrast, oxidation technologies convert lower nitrogen oxides such as nitric oxide (NO) and nitrogen dioxide (NO2) to higher nitrogen oxides such as nitrogen sesquioxide (N2O3) and nitrogen pentoxide (N2O5). These higher nitrogen oxides are highly water soluble and are efficiently scrubbed out with water as nitric and nitrous acids or with caustic solution as nitrite or nitrate salts. NOx removal in excess of 90% has been achieved using oxidation technology on NOx sources with high sulfur content, acid gases, high particulates and processes with highly variable load conditions.

The BOC LoTOx™ System is based on the patented Low Temperature Oxidation (LTO) Process for Removal of NOx Emissions, exclusively licensed to BOC Gases by Cannon Technology. This technology has met the stringent cost and performance guidelines established by the South Coast Air Quality Management District in Diamond Bar, CA and has set new lower limits for Best Available Control Technology (BACT) and Lowest Achievable Emissions Reduction (LAER). The LoTOx™ System for NOx Control uses oxygen to produce ozone as the primary treatment chemical using an ozone generator. The oxidation of NOx using ozone is a naturally occurring process in the atmosphere. The absorption of higher nitrogen oxide by water to form nitric acid is also a naturally occurring process in the atmosphere, resulting in “acid rain”. The LoTOx™ System reproduces these naturally occurring processes under controlled conditions within an enclosed system. This treatment method produces the treatment chemical, ozone, on demand from gaseous oxygen in the exact amount required for oxidation of the NOx.

A demonstration was conducted at Southern Research Institute’s (SRI) Combustion Research Facility, Birmingham, AL using a mobile demonstration trailer. The test was the first in a series of tests planned to demonstrate the effectiveness of ozone for oxidation and removal of NOx emissions from SRI’s coal-fired combustor. The results from the tests demonstrated that the LoTOx™ System is highly effective for removal of NOx emissions from as high as 350 ppmv NOx to below 50 ppmv NOx levels without significant residual ozone in the exhaust stream. The LoTOx™ System is very selective for NOx removal, oxidizing only the NOx and therefore efficiently using the treatment chemical, ozone, without causing any significant SOx oxidation and without affecting the performance of the downstream SOx scrubber. Furthermore the ozone/NOx ratios required to produce desired NOx oxidation are less than the predicted stoichiometric amounts. Various types of coals and fuel types will be used in the combustor. The information gathered will be used for the design of commercial LoTOx™ Systems for effective and efficient NOx removal at utility power plants and other large-scale NOx sources. [1]

Chemistry

The LoTOx process is based on the excellent solubility of higher order nitrogen oxides. Typical combustion processes produce NOx streams that are approximately 95% NO and 5% NO2. Both NO and NO2 are relatively insoluble in aqueous streams, therefore, wet scrubbers will only remove a few percent of NOx from the flue gas stream. Species Solubility at 25°C and 1 atm

NO 0.063 g/l, NO2 1.260 g/l

The LoTOx process uses ozone to oxidize NO and NO2 to N2O5 ,which is highly soluble, and by wet scrubbing N2O5 is easily and quickly converted to HNO3, based on the following reactions:

$NO + O_3 \rightarrow NO_2 + O_2$

$2NO_2 + O_3 \rightarrow N_2O_5 + O_2$

$N_2O_5 + H_2O \rightarrow 2HNO_3$
Both N_2O_5 and HNO_3 are extremely soluble in water. N_2O_5 reacts instantaneously with water forming HNO_3. Since HNO_3 is so highly soluble (approaching infinity) it is difficult to measure, and therefore reliable solubility data is not available in published literature. However, HNO_3 mixes with water in all proportions and therefore the N_2O_5 to HNO_3 reaction is irreversible in the presence of water. [2]

Benefits: Low Temperature, No chemical slip
Tradeoffs:

Burdens:
Ozone unused in the treatment process produces no health hazards to plant workers nor to the environment. The ozone is injected into flue gas stream where it reacts with relatively insoluble NO and NO_2 to form N_2O_3 and N_2O_5, which are highly water soluble, and are easily and efficiently removed and neutralized in a wet scrubbing system. [1]

II. Description of how to implement
A. Mandatory or voluntary
LoTOx could be the answer to achieve required limits under regional haze rule. This control technology could be an option to meet mandatory emissions limits

B. Indicate the most appropriate agency(ies) to implement
4 Corners Power Plants would implement new technology as an integrated component of emissions control system

III. Feasibility of the option
A. Technical: Low temperature reaction is good. Ozone generation and other LoTOx system components are well understood technologies used in other applications.
B. Environmental: Pilot scale demonstrations showed 90% removal, very high reduction efficiencies
C. Economic: Retrofit technologies can be expensive on existing power plants.

This technology has only been tested on pilot plants and there are no full scale installations. The technology should therefore, at this point, be considered not technically feasible.

IV. Background data and assumptions used
1. DEMONSTRATION AND FEASIBILITY OF BOC LoTOx™ SYSTEM FOR NOx CONTROL ON FLUE GAS FROM COAL-FIRED COMBUSTOR abstract, presented at 2000 Conference on SCR & SNCR for NOx Control/BOC,
http://www.netl.doe.gov/publications/proceedings/00/scr00/ANDERSON.PDF
2. CARB Innovative Clean Air Technology, "Low Temperature Oxidation System Demonstration," BOC paper 1999, http://arbis.arb.ca.gov/research/apr/past/icat99-2.pdf
3. DuPont BELCO LoTOx Technology homepage
http://www.belcotech.com/products/nox.html

V. Any uncertainty associated with the option
Medium, any retrofit technology has a degree of uncertainty. It can be difficult and expensive to retrofit emissions control technology that the plant was not originally designed for.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

EXISTING: OTHER RETROFIT TECHNOLOGIES

Mitigation Option: Baghouse Particulate Control Retrofit

I. Description of the mitigation option

Installation of baghouses at existing power plants in the Four Corners area could reduce particulate emissions by approximately 25% or more. Baghouses, or fabric filters, as they are often called, collect fly ash and other particulate matter from the coal combustion process like large vacuum cleaners. Typically a baghouse removes more than 99.8 % of the fly ash.

The original design for the two major power plants in the 4 Corners area was for electrostatic precipitators (ESPs). The ESPs on San Juan Generating Station remove approximately 99.7 % of the particulate matter from the exhaust stream. This exceeds current state and federal emissions requirements (0.1 lbs/mmBtu and 0.05 lbs/mmBtu).

The San Juan generating station is currently undergoing a series of environmental improvements between 2007 and 2009 including designing for a 0.015 lbs/mmBtu particulate limit. PNM will install fabric filters (baghouses) for all four SJGS units collect particulate emissions. The ESPs at San Juan will remain in place but will be de-energized. It is believed that a portion of the ash will continue to be removed in the ESPs (because of gravity separation) but they will not be considered a control device. One of the reasons to install the baghouses was because of PNM's commitment for Activated Carbon Injection for the removal of mercury. An ESP would not have been efficient in the collection of the activated carbon. An additional benefit of the baghouse is the reduction of opacity spikes that are caused by an increase in unburned carbon in the flyash. This unburned carbon is caused by combustion problems associated with the operation of the low-NOx burners and is not efficiently collected by an ESP. Also, we will not know until the Baghouses are installed and operational, but we do not anticipate that the actual particulate emissions will be significantly less than the current emissions. However, the permit requirement will be reduced from 0.05 lbs/mmBtu to 0.015 lbs/mmBtu.

Since all units at San Juan and Units 4 & 5 at Four Corners currently have or will have baghouses in the near future, this option will only apply to Units 1,2 & 3 at Four Corners.

Benefits: Current reported levels of particulate emissions at major power plants in the 4Corners area include: San Juan Generating Station emits approximately 673 Tons/yr, approximately .011 lbs/mmBtu; 4 Corners Power Plant emits approximately 1,187 Tons/yr, approximately .017 lbs/mmBtu (see 4CAQTF_PowerPlant_WorkGroup_ FacilityDataTableV10). Baghouse installation may result in improved particulate removal efficiencies. If baghouses could reduce emissions to .010 lbs/mmBtu, this option could lead to over 500 tons per year reduction of particulates collectively from the two largest coal fired power plants in the region.

Differing Opinion: The benefits (500 ton reduction of particulates) may be over estimated because San Juan and Four Corners Unit 4 & 5 will have baghouses and will perform at or close to the 0.01 lbs/mmBtu. The only units that would see a reduction would be Four Corners Units 1,2 & 3.

Burdens: Cost of baghouse installation on power plants

II. Description of how to implement

A. Mandatory or voluntary

Voluntary or consent decree

B. Indicate the most appropriate agency(ies) to implement
Power Plants would install

III. Feasibility of the option
A. Technical: Technology is available commercially

B. Environmental: Feasible

C. Economic: Expensive to install new technology

IV. Background data and assumptions used
1. San Juan Generating Station (SJGS) Emissions Control Current and Future, presentation for 4CAQTF, May 2006 ,http://www.nmenv.state.nm.us/aqb/4C/Docs/SanJuanGeneratingStation.pdf

2. 4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10

3. Clean Air Markets – Data and Maps – 2005 Unit Emissions Report – Emissions for San Juan Generating Station & Four Corners Steam Electric Station
Heat input for all 4 units at San Juan Generation Station 127,629,979 mmBtu in 2005.
Heat input for all 5 units combined at 4Corners Power Plant 141,394,388 mmBtu in 2005.

4. San Juan Environmental Improvement Upgrades Fact Sheet,
http://www.pnm.com/news/docs/2005/0310_sj_facts.htm

V. Any uncertainty associated with the option
Medium.

VI. Level of agreement within the work group for this mitigation option
TBD.

VII. Cross-over issues to the other Task Force work groups
None.

Mitigation Option: Mercury Control Retrofit

I. Description of the mitigation option

Existing power plants in the Four Corners area should evaluate the installation of mercury removal technology to reduce mercury emissions. According to EPA's 2005 Toxic Release Inventory report the San Juan Generating Station released 770 lbs and Four corners Power Plant released 625 lbs of mercury into the air. Activated carbon injection technology is the most likely control technology at this time. This technology has been demonstrated in several pilot studies.

The Clean Air Mercury Rule (CAMR) will require the reduction of mercury emissions from power plant beginning in 2010 with further reductions in 2018. This rule will also require the installation of mercury Continuous Emissions Monitoring systems by January 1, 2009.

San Juan Generating Station will have mercury control (activated carbon injection) on all four units by 2010 and Mercury CEMs on 2 units by 2008 and all 4 units by 2009.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory and/or Voluntary

B. Indicate the most appropriate agency(ies) to implement
Regulating agencies:
EPA Region 9 Air Programs, Navajo Nation EPA, New Mexico Environment Department

III. Feasibility of the option

A. Technical: The injection of activated carbon into the flue gas stream has been demonstrated in pilot studies to remove mercury. However, there have not been any long-term applications of this technology. Also the effectiveness of this technology has not been demonstrated on the type of coal in the San Juan Basin so the actual removal efficiency of the technology is unknown. Nevertheless, many new coal-fired power plant projects are proposing installation of activated carbon injection.

B. Environmental: Mercury emissions will be reduced, however, the addition of activated carbon to the fly ash will make the ash unsuitable for sale to the cement/concrete industry and will increase the amount of fly ash that will have to be disposed.

C. Economic: The cost of additional equipment for ACI injection is relatively small, however, the annual operating and maintenance cost can be significant because of the cost of the activated carbon. Also there currently is a limited supply of activated carbon. The increase cost for ash disposal could be significant. Also, ACI injection requires a bag house or fabric filter for particulate control. This cost would be significant if this technology would have to be retrofitted to existing units.

IV. Background data and assumptions used N/A.

V. Any uncertainty associated with the option Medium.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

EXISTING: STANDARDS

Mitigation Option: Harmonization of Standards

I. Description of the mitigation option,
This option would require existing power plants to meet the most stringent standard of any governmental agency in the region, i.e., the strictest state, federal, or tribal standard. At present facilities are subject to varying standards depending on where they are located, even though emissions affect the entire area and beyond.

This option is limited to existing power plants on the basis that new power plants are held to Best Available Current Technology (BACT) limitations on controlled emissions, which are usually much lower than current state or federal air standards.

One of problems in the Four Corners area is the aging fleet of large power plants. These older power plants have significantly higher emissions than potential new sources. The two largest generating stations in the Four Corners Region, Four Corners Power Plant (FCPP) and the San Juan Generating Station (SJGS), are regulated by different agencies even though they are within 30 miles of each other. San Juan Generating Station is being held to more stringent regulations by the New Mexico Air Quality Bureau regulations.

The burden of this requirement to adopt more stringent regulations would fall on the owners of the facilities and might also lead to the eventual retirement of some older Four Corner area power plants. However, the long-term effect of this rule, especially if applied to other multi-state regions over time, might lead to standardized regulations, also a benefit, if the new standards converged on the most stringent requirement.

II. Description of how to implement
This rule should be mandatory and phased in over a designated period of time.

A valuable lesson is to be learned from the Four Corners Power Plant jurisdiction quandary. The Navajo Tribe ruled that the State of NM cannot regulate and enforce FCPP emissions. Very recently, a lawsuit was filed against the Federal EPA regarding FCPP emissions. This lawsuit may have expedited the current series of action by the Federal EPA such as public sessions, the FIP, etc. The FCPP is on tribal land, but the air emissions affect the entire Four Corners area. Somehow, a regulatory agency responsible for governing and enforcing emissions of present and future power plants and oil and gas facilities should be agreed upon by all entities.

The area's ozone problem is an example of why it is important to have one regulatory agency. The Four Corners area has unusually high volumes of ground level ozone. The Four Corners Ozone Task Force (FCOTF) has been working for the past several years on ozone mitigation options. The FCOTF is working closely with EPA Region 6. Recently EPA Region 9 officials came to the area to talk about the proposed Desert Rock coal fired power plant. This area's ozone problems were not addressed by EPA Region 9 in the Desert Rock Proposed PSD Permit. In order to avoid costly environmental oversights and/or confusion, only one EPA Region should be designated as the Federal Agency to regulate and enforce in an area such as the Four Corners.

Differing Opinion: Implementing this option could initially be voluntary, as it would ultimately require changes to the Clean Air Act and/or Code of Federal Regulations to address tribal authority over air programs, and the role of the Federal Implementation Plan.

III. Feasibility of the Option

Technical issues: none, technology currently exists to meet the most stringent existing requirement

Environmental issues: Benefits of stricter standards are intuitive. The following are examples of significant disparities in state and federal limits:

For example, the current State permit limit for NOx emissions from San Juan Generating Station is 0.46 lbs/mmBtu. The federal limits for NOx at Four Corners Power Plant are 0.65 – 0.85 lbs/mmBtu. San Juan Generating Station NOx emissions rate is approx. 0.4 lbs/mmBtu or 26,800 Tons/yr. Four Corners Power Plant, under the federal regulation, emits approx 0.6 lbs/mmBtu or approx 41,700 tons/yr

The state limit for SO_2 emissions from San Juan Generating Station is 0.65 lbs/mmBtu. The federal limit applied to Four Corners Power Plant is 1.2 lbs/mmBtu. The state permit limit for PM emissions from San Juan Generating Station is 0.05 lbs/mmBtu. The Federal PM standard is 0.1 lbs/mmBtu.

Economic: Implementation of resulting standards could be expensive. Experience of the political unit currently having the strictest standard could provide some data on the cost. In any case, the standard, even though not industry-wide, would be applicable area-wide and therefore more fair to competing power generators

Political issues: resistance would be great, just as it is now to tightening of standards. Effective implementation of this idea might require creation of a Four Corners regional authority or special district, which might require enabling legislation: the difficulty of accomplishing this is unknown.

IV. Background data and assumptions

The Federal/State PSD rules are applied industry wide for new power plants and existing power plants with major modifications in NAAQS attainment areas. Existing power plants in different jurisdictions continue to be regulated by different standards even though they are in the same air basin. This option would be a step in harmonizing standards. It is clear that the two plants we have heard from could meet tighter standards, especially when applied industry-wide; but since they are not required to do so, they cannot get their owners to support meeting them. It is intuitive that if any installation in the Four Corners region using San Juan Basin coal can meet the tightest standard, they all can over a reasonable period of time.

Green House Gases Such as Carbon Dioxide –
It is becoming more and more apparent that Global Warming or Climate Changes is a world wide problem. Reductions in carbon dioxide emissions, one of the green house gases, should be addressed in the Mitigation Options for all existing and future coal fired power plants in the San Juan Basin. The carbon dioxide issue will have to be dealt with sooner or later and the sooner, the better.

New Mexico Environmental Regulations for Air Quality may be found at:
http://www.nmenv.state.nm.us/aqb/regs/index.html

V. Any uncertainty associated with the option

There is a high level of uncertainty in getting something like this passed politically and how long it would take is an unknown.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues Oil and Gas Work Group, Other Sources Work Group.

EXISTING: MISCELLANEOUS

Mitigation Option: Emission Fund

I. Description of the mitigation option

This option would establish an emissions fund for emitters of one or more air pollutants of concern, such as nitrogen oxides. Sources emitting more than a specified amount annually would pay by the ton emitted into a fund that would then be used for environmental improvement projects. There should be no maximum number of tons over which fees wouldn't be paid.

The fund should be used for environmentally beneficial projects, to be decided by the administering body (see below). One option is to have a grant system whereby applications are made to the fund by anyone—regulated community, environmental community, public, academia, etc—and the administering body would have set criteria against which they evaluated each request. Another option is to specify the allowable uses of the fund, such as for the development or investment in innovative technologies.

Benefits: Ideally, emitters required to pay per ton emitted would have an incentive to emit less. To make this incentive effective, the fee per ton would need to be relatively high. A thorough search of similar programs and any evaluations of those programs should be done to determine what fee level would provide an effective incentive. Monetary incentives could result in emission reductions at significantly lower costs than "command and control" regulation. Emission fees also work to "internalize the externalities" involved in air emissions and environmental degradation by recognizing and attempting to account for the social costs of the operations of the emitters.

Burdens: the primary burden would be on the emitter, to pay into the fund based on annual emissions. There would be some administrative burden, lessened by using existing reporting and oversight frameworks to implement the program.

II. Description of how to implement

A. Mandatory of voluntary: Payment into an emission fund would be mandatory for a defined size or class of sources

B. Most appropriate agency to implement: These programs have generally been administered by state agencies. Tribal air quality agencies could also develop and implement an emissions fund. An oversight committee or the air quality entity with regulatory authority would have authority to administer the fund. The committee or board should have members representing the regulated community, environmental community and general public.

The program could be phased in: fees per ton of emissions of specified pollutant(s) could gradually be increased over 5-10 years. The program could be based on existing permitting systems: fees would be based on the number of tons reported emitted, via existing reporting requirements within permits or any other existing framework for reporting.

III. Feasibility of the option

Emissions funds for air pollution are used in France, Japan and many states as well. There are no technical feasibility issues associated with this option.

IV. Background data and assumptions used

Stavins, R. (Ed.) (2000). *Economics of the Environment (4^{th} Ed.).* WW Norton: New York, New York.
New Hampshire Code of Administrative Rules, Chapter Env-A 3700: *NOx Emissions Reduction Fund for NOx-Emitting Generation Sources.*

Ohio EPA *Synthetic Minor Title V Facility Emission Fee Program*. http://www.epa.state.oh.us/dapc/synmin.html. (via statute--need cite).

Texas Administrative Code, Title 30, Part 1, Chapter 101, Subchapter A, Rule sec. 101.27: *Emissions Fees*

V. Uncertainty

VI. Level of agreement within workgroup

VII. Cross-over issues to other workgroups

The oil and gas industry could be subject to the emissions fund.

PROPOSED POWER PLANTS: DESERT ROCK ENERGY FACILITY

Mitigation Option: Desert Rock Energy Facility Stakeholder Funding to and Participation in Regional Air Quality Improvement Initiatives such as Four Corners Air Quality Task Force

I. Description of the mitigation option

Sithe Global and other stakeholders in Desert Rock Energy Facility will provide time and resource commitments to participate in inter-agency environmental initiatives to improve air quality in the Four Corners area.

Background:
Sithe Global Power, LLC proposes to construct a 1,500 Megawatt hybrid dry cooled coal-fired electric power-generating plant south of Farmington in northwestern New Mexico, per the project development agreement entered into with Diné Power Authority (1).

The proposed Desert Rock Energy Facility is located within the New Mexico portion of the Four Corners Interstate Air Quality Control Region. The area is currently designated as attainment for all regulated pollutants: nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter less than 10 microns in aerodynamic diameter (PM10), lead, and ozone (regulated as volatile organic compounds (VOC) and oxides of nitrogen (NOx)). There are concerns, however, with air pollution in the area and the effects on human health, visibility, and other air quality related values. The Facility's surrounding area is classified as Class II. The nearest Class I area is the Mesa Verde National Park, which is located approximately 75 kilometers (km) north of the site. The Grand Canyon National Park is located approximately 290 km west of the site (3). There are nine National Park Service Class I areas and six Forest Service Class I areas within 300 km of this proposed facility.

While the Desert Rock Energy Facility is using newer environmental emission control technology that on average have higher reduction efficiencies than existing facilities, the proposed power plant will still be adding substantial NO2, SO2, particulate, and other emissions to the Four Corners Area. See appendix 1.

Industry support would help to provide the resources necessary to ensure the air quality in the Four Corners, including our National Ambient Air Quality Standards (NAAQS) attainment, is maintained. There are substantial stakeholder interests in having air quality cleaner than simply meeting the NAAQS, for example, to improve visibility.

Desert Rock Energy LLC submitted a set of comments on the Four Corners Air Quality Task Force report during the public comment period. Desert Rock's comments included a discussion of a Voluntary Regional Air Quality Improvement Plan, CO2 emissions, and IGCC in relation to the proposed facility. The comments are located in an appendix at the end of the Power Plants section.

Benefits: Environmental initiatives will be supported by industries that contribute to the air quality issues. Much needed financial support will be provided to regional environmental initiatives. Information resources will be provided to help in the environmental regulation planning process.

Tradeoffs: None

Burdens: Sithe Global and other stakeholders will provide time and resource commitment to participate in inter-agency environmental initiatives in the Four Corners area.

II. Description of how to implement
A. Mandatory or voluntary
Voluntary or mandatory

Differing Opinion: Mandatory: because of the fact that the Four Corners Area is already heavily polluted by several industrial sources such as the Four Corners Power Plant and the San Juan Generating Facility, over 19,000 oil and gas wells (over 12,500 new wells are planned in the next two decades), a fast growing population, more motor vehicles, etc.

B. Indicate the most appropriate agency(ies) to implement
Environmental Protection Agency (EPA) Air Programs
Desert Rock Energy Project voluntary participation

Differing Opinion: According to an article in the December 11, 2006 "Farmington Daily Times" titled "Navajo Nation to Partially Own Desert Rock", "Representatives from the Dine Power Authority (DPA) say they will operate the proposed Desert Rock Power Plant with at least one degree of separation from the Navajo Nation Environmental Protection Agency (NNEPA) which will have oversight of the project." This should be a major concern. The Desert Rock Power Plant if built, must be closely monitored and enforcement must be very strict. There are concerns that a conflict of interest may exist. The Federal EPA should be the governing agency.

III. Feasibility of the option
Feasible.

IV. Background data and assumptions used
Literature cited
(1) Desert Rock Energy Project FACT SHEET #1, DEC 2004 (http://www.desertrockenergy.com/)
(2) 4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10
(3) AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)

V. Any uncertainty associated with the option
Low.

VI. Level of agreement within the work group for this mitigation option.
To Be Determined.

VII. Cross-over issues to the other Task Force work groups
None.

Table 1. Estimated Maximum Annual Potential Emissions from Desert Rock Energy Facility [Source: AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)]

Pollutant	PC Boilers (tpy)	Auxiliary Boilers (tpy)	Emergency Generators (tpy)	Fire Water Pumps (tpy)	Material Handling (tpy)	Project Estimated Emissions
NOx	3,315	7.13	2.26	0.41	n/a	3,325
CO	5,526	2.55	0.17	0.031	n/a	5,529
VOC	166	0.17	0.11	0.019	n/a	166

SO_2	3,315	3.61	0.068	0.012	n/a	3,319
PM[2]	553	1.02	0.083	0.015	16.1	570
PM_{10}[3]	1,105	1.68	0.077	0.014	12.9	1,120
Lead	11.1	0.00064	0.00012	0.0000022	n/a	11.1
Fluorides	13.3	neg	neg	neg	neg	13.3
H_2SO_4	221	0.062	0.002	0.0004	n/a	221
Mercury	0.057	0.000071	neg	neg	n/a	0.057

[1]tpy -tons per year
[2]PM is defined as filterable particulate matter as measured by EPA Method 5.
[3]PM_{10} is defined as solid particulate matter smaller than 10 micrometers diameter as measured by EPA Method 201 or 201A plus condensable particulate matter as measured by EPA Method 202. EPA is treating PM_{10} as a surrogate for $PM_{2.5}$.

Mitigation Option: Emissions Monitoring for Proposed Desert Rock Energy Facility to be used over Time to Assess and Mitigate Deterioration to Air Quality in Four Corners Area

I. Description of the mitigation option

The present proposed monitoring permit requirements for Desert Rock Energy Facility address only measurement of permit standards while there is another category of monitoring which could and should be done. This category would be data needed or useful for the evaluation of mitigation options in the present or the future.

PROPOSED ADDITIONAL MONITORING

a. PM2.5 continuous monitoring requirement.

The Four Corners region has several class 1 areas and a long term requirement by the EPA for improving visibility. PM2.5 is a critical element in this problem and future mitigation of it will require precise knowledge of the relative contributions from multiple and varied sources. This could come about by inclusion in the EPA permit conditions or by the company adding it to what they are doing to protect themselves from future finger pointing. Either way the data needs to be publicly available so those evaluating mitigation options have the use of it.

Total filterable PM CEMs have been certified by EPA. EPA contends that there is no currently certified method to continuously monitor PM_{10} or $PM_{2.5}$. However, there are some PM CEMs vendors that suggest CEMS can be modified to monitor a certain particulate size fraction.

b. Speciated Mercury (Hg) stack emission plus a plume contact measurement.

This region now has several lakes where restrictions of fishing exist because of Hg levels in the fish. The sources of Hg are multiple (geology, mining, oil & gas, agriculture, and power plants) to devise a proper mitigation plan the Hg species will need to be known so that sources can be identified and contribution determined. Models which predict Hg species in the environment from those found in the stack have shown problems. (Hg Speciation in Coal-fired Power Plant Plumes Observed at Three Surface Sites in the SE U.S.,Environ. Sci. Technol.2006, 40, 4563-4570:Modeling Hg in Power Plant Plumes, Environ. Sci. Technol,2006, 40,3848-3854) For this reason sampling at plume ground contact needs to be done to determine species for our environment and plant and coal types as the Hg enters the environment since we can not count on modeling to give correct Hg speciation. The stack sampling should be required under the permit plume surface contact samples however might be a cooperative venture between state or tribal personnel and the company. (State or Tribal personnel taking the sample and this sample then run by the company with the stack sample.)

c. VOC sampling in addition to that presently specified in the permit.

While the VOC's are nowhere near levels that would cause general health problems they are critical to the processes involved in the visibility problem which needs addressing. VOC's react in the plume after emission and change. A measurement of the VOC's after the initial reaction in the plume would be advantageous since it would give what is present to react to give the visibility problems. The VOC's present after this initial reaction is usually predicted by modeling however the literature indicates there are some problems with this approach measurements made at the plume ground contact could be a joint operation. State or Tribal personnel might collect a sample with the company running the sample with their stack sample.

II. Description of how to implement

A. Mandatory or voluntary

Desert Rock Energy Facility would be responsible for facility monitors

There are concerns that there are not enough monitors in place in the Four Corners Area and that the existing monitors are not placed in optimum locations. Several more monitors in logical locations must be installed in order to accurately measure emissions. The Federal, State, and Tribal EPA agencies should be responsible for collection and analyzing samples. The Four Corners Power Plant and the San Juan Generating Station are among the dirtiest coal fired power plants in the Nation. Desert Rock must be placed under strict scrutiny. The Four Corners Area is already close to ground level ozone levels of non-attainment. The area cannot afford further degradation of the air quality.

B. Indicate the most appropriate agency(ies) to implement
State or Tribal personnel might collect and analyze some samples

III. Feasibility of the option
A. Technical
B. Environmental
C. Economic

*Monitoring Work Group – assess the feasibility (technical, environmental, and economic) of conducting the proposed monitoring.
*Cumulative Effects Work Group – Will the proposed additional monitoring in this mitigation option be useful in assessing the Desert Rock Energy Facility point source contributions to the cumulative Four Corners area air quality?

IV. Background data and assumptions:

V. Any uncertainty associated with the option (Low, Medium, High)
Low

VI. Level of agreement within the work group for this mitigation option
TBD

VII. Cross-over issues to the other source groups
None

Mitigation Option: Coal Based Integrated Gasification Combined Cycle (IGCC)

<u>I. Description of the mitigation option</u>

Consideration of IGCC technology, as an alternative to a pulverized coal fired boiler, should be considered in the BACT analysis.

Sithe Global Power, LLC proposes to construct a 1,500 Megawatt hybrid dry cooled coal-fired electric power-generating plant south of Farmington in northwestern New Mexico, per the project development agreement entered into with Diné Power Authority (1).

The proposed Desert Rock Energy Facility is located within the New Mexico portion of the Four Corners Interstate Air Quality Control Region. The area is currently designated as attainment for all regulated pollutants: nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter less than 10 microns in aerodynamic diameter (PM10), lead, and ozone (regulated as volatile organic compounds (VOC) and oxides of nitrogen (NOx)). There are concerns, however, with air pollution in the area and the effects on human health, visibility, and other air quality related values. The Facility's surrounding area is classified as Class II. The nearest Class I area is the Mesa Verde National Park, which is located approximately 75 kilometers (km) north of the site. The Grand Canyon National Park is located approximately 290 km west of the site (2). There are nine National Park Service Class I areas and six Forest Service Class I areas within 300 km of this proposed facility.

On July 7, 2006, the Environmental Protection Agency (EPA) released a technical report titled "The Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies." The Report provides information on the environmental impacts and costs of the coal-based integrated gasification combined cycle (IGCC) technology relative to conventional pulverized coal (PC) technologies.

"IGCC is a power generation process that uses a gasifier to transform coal (and other fuels) to a synthetic gas (syngas), consisting mainly of carbon monoxide and hydrogen. The high temperature and pressure process within an IGCC creates a controlled chemical reaction to produce the syngas, which is used to fuel a combined cycle power block to generate electricity. Combined-cycle power applications are one of the most efficient means of generating electricity because the exhaust gases from the syngas-fired turbine are used to create steam, using a heat recovery steam generator (HRSG), which is then used by a steam turbine to produce additional electricity (3)."

Consideration of IGCC technology, as an alternative to a pulverized coal fired boiler, was not included in the BACT analysis for the Desert Rock Energy Facility (2).

Desert Rock Energy LLC submitted a set of comments on the Four Corners Air Quality Task Force report during the public comment period. Desert Rock's comments included a discussion of IGCC. Please see the comment in its entirety in the appendix to the Power Plants section.

<u>Benefits:</u> For traditional pollutants such as nitrogen oxides (NOx), sulfur dioxide (SO2), particulate matter (PM) and mercury (Hg), IGCC is inherently lower polluting than the current generation of traditional coal-fired power plants. IGCC also has multi-media benefits, as it uses less water than Pulverized Coal facilities. IGCC also produces a solid waste stream that can be a useful byproduct for producing roofing tiles and as filler for new roadbed construction. IGCC also has the potential to reduce solid waste by using as fuel a combination of coal and renewable biomass products (3).

IGCC is considered one of the most promising technologies to reduce the environmental impacts of generating electricity from coal. EPA has undertaken several initiatives to facilitate the development and deployment of this technology

IGCC thermal performance (efficiency and heat rate) is significantly better than current generation pulverized coal technologies in the US;

The Capture of CO2 emissions from IGCC plants would be cheaper and less energy intensive than in conventional coal plants (3, 6)

Tradeoffs:
Burdens: IGCC has 10 – 20 % higher capital costs than conventional PC plants [3]
When carbon capture becomes mandatory, that cost disadvantage will likely disappear.

II. Description of how to implement

A. Mandatory or voluntary
Mandatory to look at IGCC as a Best Available Control Technology option for future power plants in the Four Corners area

Permit levels could be set based upon IGCC performance. It would be up to the source how to meet those limits with whatever technology it chooses.

This could be a new legislative requirement at the State or Tribal level

B. Indicate the most appropriate agency(ies) to implement
Policy options for use of Integrated Gasification Combined Technology could be developed by Environmental Protection Agency (EPA), Department on Energy (DOE), New Mexico Energy, Minerals, and Natural Resources Department (NMEMNRD).

*EPA could designate IGCC as a Best Available Control Technology.

Differing Opinion:
Assuming that coal gasification is an innovative fuel combustion technique for producing electricity from coal, EPA does not believe Congress intended for an "innovative fuel combustion technique" to be considered in the BACT review when application of such a technique would redesign a proposed source to the point that it becomes an alternative type of facility. In prior EPA decisions and guidance, EPA does not consider the BACT requirement as a means to redefine the basic design of the source or change the fundamental scope of the project when considering available control alternatives. Therefore, the question is whether IGCC results in a redefinition of the basic design of the source if the permittee is proposing to build a supercritical pulverized coal (SCPC) unit. EPA's view is that applying the IGCC technology would fundamentally change the scope of the project and redefine the basic design of the proposed source if a supercritical pulverized coal unit was the proposed design. Accordingly, consistent with our established BACT policy, we would not require an applicant to consider IGCC in a BACT analysis for a SCPC unit. Thus, for such a facility, we would not include IGCC in the list of potentially applicable control options that is compiled in the first step of a top-down BACT analysis. Instead, we believe that an IGCC facility is an alternative to an SCPC facility and therefore it is most appropriately considered under Section 165(a)(2) of the CAA rather than section 165(a)(4).

Four Corners state legislatures and/or Tribal Nations could legislate that IGCC be considered?

III. Feasibility of the option

A. Technical:
Development and implementation of IGCC technology is relatively new compared with the PC technology that has hundreds or thousands of units in operation globally. Currently in the US there are two gasification unit installations using coal to make electric power as the primary product. The two IGCC plants in commercial operation include the Tampa Electric Polk Power Station in Florida and the Wabash River Coal Gasification Repowering Plant in Indiana. Each has been in operation since the mid-1990s. Recently, however, a number of companies have announced plans to build and operate additional IGCC facilities in the US (3).

These plants have yet to maintain better than 80% availability after more than 10 years of operation. Improved process control strategies are needed to ensure optimum operation over the full range of operating conditions. Real time coal quality analysis is needed to stabilize the coal gasifier process. Several areas of instrumentation development are warranted by the challenging physical conditions of the high temperature, abrasive, slagging gasifier environment. Other areas of the IGCC process face unique challenges that require development efforts to achieve the high availability rate needed for economic viability.

IGCC plants have not been demonstrated larger than 300 MW. For Desert Rock, more/larger gasifiers and several combustion turbines would be needed to attain 1500 MW. This technology is promising, but needs much development funding before the investment community would take on the risk of building such a large IGCC facility.

B. Environmental: This is a process control option

C. Economic: IGCC has higher capital costs than conventional PC plants (3).

IGCC has not demonstrated the typical 85-95% PC plant availability factors necessary for viable on-going profitable operation.

Historically, concerns about operational reliability and costs presented issues of uncertainty for IGCC technology and impeded its deployment. Such conditions are changing toward the more rapid advancement of the IGCC option. IGCC is a versatile technology and is capable of using a variety of feed stocks. In addition to various coal types, feed stocks can include petroleum coke, biomass and solid waste. Along with electricity production, IGCC facilities are able to co-produce other commercially desirable products that result from the process. Some of these products include steam, oxygen, hydrogen, fertilizer feed stocks and Fischer-Troph fuels (3).

The operational versatility noted above for IGCC technology may mitigate the risk of higher costs. In addition, under the Energy Policy Act of 2005, there are provisions for tax credits and a DOE Loan Guarantee Program to provide incentives to facilitate the deployment of IGCC technology.
In 1994 EPA established the Environmental Technology Council (ETC) to coordinate and focus the Agency's technology programs. The ETC strives to facilitate innovative technology solutions to environmental challenges, particularly those with multi-media implications. The Council has membership from all EPA technology programs, offices, and regions and meets on a regular basis to discuss technology solutions, technology needs and program synergies. One of the technologies identified as a promising option to address the production of energy from coal in an environmentally sustainable way is IGCC. This technical report is part of the ETC initiative and supports the combined efforts of EPA and the Department of Energy to advance the use of IGCC technology (3).

IV. Background data and assumptions used:
(1) Desert Rock Energy Project FACT SHEET #1, DEC 2004 (http://www.desertrockenergy.com/)

(2) AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)
(3) Technical Report on the Environmental Footprint and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, Fact Sheet: http://www.epa.gov/airmarkets/articles/IGCCfactsheet.html
(4) Wabash River IGCC Topical Report 2000 – www.fossil.energy.gov/programs/powersystems/publications/Clean_Coal_Topical_Reports/topical20.pdf
(5) Pioneering Gasification Plants (DOE) – http://www.fe.doe.gov/programs/powersystems/gasification/gasificationpioneer.html
(6) Scientific American, September 2006 article, "What to do about Coal," pp. 68-75
(7) ISA-2005 "I & C Needs of Integrated Gasification Combines Cycles" Jeffrey N. Phillips, Project Manager, Future Coal Generation Options, Electric Power Research Institute – presented at the 15th Annual Joint ISA POWID/EPRI Controls and Instrumentation Conference, 5-10 June 2005, Nashville, TN

V. Any uncertainty associated with the option

Medium. Integrated Gasification Combined Cycle (IGCC) is still a relatively new technology. There are coal gasification electric power plants in the US and other nations.

VI. Level of agreement within the work group for this mitigation option

To Be Determined

VII. Cross-over issues to the other Task Force work groups:

None

Mitigation Option: Desert Rock Energy Facility Invest in Carbon Dioxide Control Technology

I. Description of the mitigation option

Sithe Global Power, LLC proposes to construct a 1,500 Megawatt hybrid dry cooled coal-fired electric power-generating plant south of Farmington in northwestern New Mexico, per the project development agreement entered into with Diné Power Authority (1).

The proposed Desert Rock Energy Facility is located within the New Mexico portion of the Four Corners Interstate Air Quality Control Region. The area is currently designated as attainment for all regulated pollutants: nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter less than 10 microns in aerodynamic diameter (PM10), lead, and ozone (regulated as volatile organic compounds (VOC) and oxides of nitrogen (NOx)). The Facility's surrounding area is classified as Class II. The nearest Class I area is the Mesa Verde National Park, which is located approximately 75 kilometers (km) north of the site. The Grand Canyon National Park is located approximately 290 km west of the site (2). There are nine National Park Service Class I areas and six Forest Service Class I areas within 300 km of this proposed facility.

CO_2 emissions are not regulated; however, they are the primary Greenhouse gas that causes global warming.

In June 2005, the Climate Change Advisory Group was created in New Mexico as the result of an executive order from the Governor. The Climate Change Advisory Group (CCAG) is tasked with preparing an inventory of current state (New Mexico) Greenhouse gas emissions, as well as a forecast of future emissions. An action plan with recommendations to reduce Greenhouse gas emissions in New Mexico is also being prepared (3).

The process of generating electricity is the single largest source of greenhouse gas emissions in the United States (34 percent) [4]. CO_2 emissions. The Desert Rock Energy Facility will contribute approximately 11,000,000 Tons/yr CO_2 emissions (5, 6).

Desert Rock is a new proposed power plant in the Four Corners area. Technology is now available to capture and store CO_2 emissions. Many of these technologies are easier and less expensive if integrated into the design and construction of the power plant, rather than added later as retrofits. Retrofitting generating facilities for Carbon Capture and Storage (CCS) is inherently more expensive than deploying CCS in new plants (7).

CO2 capture and storage involves capturing the CO2 arising from the combustion of fossil fuels, as in power generation, or from the preparation of fossil fuels, as in natural-gas processing. Capturing CO2 involves separating the CO2 from some other gases. For example in the exhaust gas of a power plant other gases would include nitrogen and water vapor. The CO2 must then be transported to a storage site where it will be stored away from the atmosphere for a long period of time. In order to have a significant effect on atmospheric concentrations of CO2, storage reservoirs would have to be large relative to annual emissions. (IPCC, 2001)

This mitigation option is for Desert Rock Energy Facility and any other proposed power plants to invest into CO_2 emissions control and capture technologies. Desert Rock is in a unique situation to set an example and take the lead in this emissions reduction field.

Desert Rock Energy LLC submitted a set of comments on the Four Corners Air Quality Task Force report during the public comment period including a discussion of CO2 emissions. The comments are located in an appendix at the end of the Power Plants section.

Benefits: Reduced CO_2 emissions
Tradeoffs: None
Burdens: CO_2 control technology is expensive. Burden would be on the power plant; however, there may be some funding for the innovative technologies that would be used.

II. Description of how to implement
A. Mandatory or voluntary
Voluntary

Differing Opinion: According to experts, Desert Rock, if built, would be the seventh largest source of greenhouse gas pollution in the Western United States. It is expected that Desert Rock will emit over 11million tons of carbon dioxide per year. Emission controls on carbon dioxide will most likely be required in the very near future. Carbon dioxide emission reduction technology should be mandatory on the Desert Rock facility.

B. Indicate the most appropriate agency(ies) to implement
Environmental Protection Agency (EPA) Region 9 Air Program
Navajo Nation Air Programs
Industry leadership

EPA Climate Protection Partnership is a possible or New Mexico's San Juan Voluntary Innovative Strategies for Today's Air Standards (VISTAS) are possible vehicles for this mitigation option.

III. Feasibility of the option
A. Technical: Technologies exist; many are in the research and development phase. Technological components are commercially ready in unrelated applications (7).

B. Environmental: Capturing and storing CO_2 emissions is difficult. Integrated systems have yet to be constructed at necessary scales. Feasibility question remains whether CO_2 could be stored without substantial leakage over time

C. Economic: Capturing and storing CO_2 emissions can be expensive.

IV. Background data and assumptions used
(1) Desert Rock Energy Project FACT SHEET #1, DEC 2004 (http://www.desertrockenergy.com/)
(2) AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)
(3) Climate Change Advisory Group (CCAG) homepage: http://www.nmclimatechange.us/index.cfm
(4) EPA Climate Protection Partnerships: http://www.epa.gov/cppd/other/energysupply.htm
(5) 4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10
(6) San Juan Generating Station has a total 1798 MW generation capacity, and emits approximately 13,097,000 Tons CO_2/yr. Approx 7,300 Tons CO_2 per MW generation capacity. San Juan Generating Station CO_2 rationing by MW is used as estimation for CO_2 emissions from Desert Rock Energy Facility. Based on this assumption, the CO_2 emissions from Desert Rock Energy Facility will be approximately 11,000,000 Tons/yr.
(7) Scientific American, September 2006 article, "What to do about Coal," pp. 68-75

V. Any uncertainty associated with the option High

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups None

Mitigation Option: Federal Land Manager Mitigation Agreement with Desert Rock Energy Facility

I. Description of option

Background

Sithe Global Energy (Sithe) is proposing the Desert Rocky Energy Facility (DREF) on the Navajo Nation in northwestern New Mexico. The proposed facility would be within 300 km of 27 National Park Service units, nine of which are Class I areas, and six are U.S. Forest Service Class I areas. The proposed facility will have two 750 megawatt pulverized-coal boilers, and would be well-controlled for a coal-fired power plant. SO2 emissions would be controlled to 3,315 tons per year with Wet Limestone Scrubbers, and NOx emissions would be controlled to 3,315 tons per year with Low-NOx burners and Selective Catalytic Reduction. Despite these controls, the National Park Service and U.S. Forest Service have concluded that the emissions from DREF, absent mitigation measures, would have an adverse impact on visibility at four or more Class I areas in the region. There are also concerns with the emissions contributing to cumulative negative impacts in the region as a whole.

The permitting authority for the Desert Rock Energy Facility is the Environmental Protection Agency (EPA) Region 9, because the facility would be located on the Navajo Reservation, where neither the State of New Mexico (or Arizona) nor the Navajo Nation have permitting authority. For over two years, the National Park Service and the U.S. Forest Service worked closely with Sithe, EPA and tribal representatives to ensure the potential impact of the proposed facility were carefully analyzed. When it became evident that emissions from the facility could adversely impact visibility in several Class I areas, the energy company suggested mitigation measures intended to produce a net environmental improvement in the area, notwithstanding construction and operation of the DREF. Sithe and the federal land managers (FLMs) both sought to avoid a formal adverse impact determination that would jeopardize the issuance of the air quality permit. Negotiations ensued and resulted in an agreement in principle on substantive mitigation measures in April of 2006.

In July, 2006, EPA issued a proposed PSD permit for the facility but did not include the agreed-upon mitigation measures. EPA reasoned that mitigation measures should not be included as part of the permit absent a formal declaration of adverse impact by the FLM.
Both the National Park Service and the U.S. Forest Service have asked EPA to include the mitigation measures in the PSD permit. In the absence of the terms of the agreement in principle included as part of the final PSD permit, Task Force members are interested in ensuring the measures will be put in place to avoid adverse impacts to air quality related values in Class I areas and the region as a whole will be avoided throughout the life of the facility.

Sulfur Dioxide Mitigation

The following options outline the sulfur dioxide mitigation strategy for the DREF. The choice between Option A or Option B shall be made by Sithe or its assigns prior to the commencement of DREF plant operations.

Option A: For the purposes of mitigating potential air quality impacts, including potential visibility and acid deposition impacts, of the DREF at Class I and Class II air quality areas in the region potentially affected by DREF, Sithe[1] shall develop or cause to be developed a capital investment project or projects that generate Emission Reduction Credits from physical and/or operational changes that result in real emission reductions at one or more Electric Generating Units[2] (EGUs) within 300 km of the DREF and retire sulfur dioxide[3] Allowances in accordance with the following:

- The number of sulfur dioxide Emission Reduction Credits required for the respective calendar year shall be determined by DREF's actual sulfur dioxide emissions, in tons, plus 10%, measured as set forth in the next paragraph below.
- The amount of Emission Reduction Credits achieved would be determined by comparing the emission rate (in tons) during the year for which the reduction is claimed to a baseline emission rate. The baseline emission rate shall be the average emission rate (in tons per year) during the two-year period prior to any emission reduction taking place.
- Acceptable sulfur dioxide Emission Reduction Credits under this condition shall be allowances originating from facilities that were allocated sulfur dioxide Allowances under 40 CFR 73[4] and that are located within 300 km of the DREF facility.
- The vintage year of the Emission Reduction Credits shall correspond to the year that is being mitigated. Sithe shall retire the required Emission Reduction Credits by transferring an equivalent number of Allowances into account #XXX with the U.S. EPA Clean Air Markets Division[5]. Except for Sithe's purposes under Title IV, these retired Allowances can never be used by any source to meet any compliance requirements under the Clean Air Act, State Implementation Plan, Federal Implementation Plan, Best Available Retrofit Technology requirements, or to "net-out" of PSD. However, surplus Emission Reduction Credits could be used at the discretion of the holder of the credits.
- Sithe shall submit a report to the EPA Region 9 Administrator (or another party acceptable to the Federal Land Managers) no later than 30 days after the end of each calendar year which shall contain the amount of sulfur dioxide emitted; amount, facility, location of facility, vintage of Emission Reduction Credits retired; proof that Emission Reduction Credits/Allowances have been transferred into account #XXX; and any applicable serial or other identification associated with the retired Emission Reduction Credits/Allowances.

Due to the actual emission reductions obtained from nearby sources under this Option, the Federal Land Managers prefer this approach to mitigating DREF's air quality impacts.

Or,

Option B: For the purposes of mitigating potential air quality impacts, including potential visibility and acid deposition impacts, of the DREF at Class I and Class II air quality areas in the region potentially affected by DREF, Sithe shall obtain and retire sulfur dioxide "Mitigation Allowances" from one or more EGUs within 300 km of the DREF in accordance with the following:

- In addition to those Allowances required under Title IV, the required number of sulfur dioxide "Mitigation Allowances" for the respective calendar year shall equal DREF's actual total sulfur dioxide emissions, in tons.
- Acceptable sulfur dioxide "Mitigation Allowances" under this condition shall be from facilities that were allocated sulfur dioxide Allowances under 40 CFR 73 and that are located within 300 km of the DREF. However, the total annual cost of "Mitigation Allowances" purchased beyond those regular Allowances required by Title IV is not to exceed three million dollars[6]. Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining emission reductions, Sithe may obtain physical emission reductions at sources not granted allowances under 40 CFR 73.
- The vintage year of the "Mitigation Allowances" shall correspond to the year that is being mitigated. Sithe shall retire these "Mitigation Allowances" by transferring them into account #XXX with the U.S. EPA Clean Air Markets Division. These retired "Mitigation Allowances" beyond Title IV can never be used by any source to meet any compliance requirements under the Clean Air Act, State Implementation Plan, Federal Implementation Plan, Best Available Retrofit Technology requirements, or to "net-out" of PSD.

- Sithe shall submit a report to the EPA Region 9 Administrator (or another party subject to approval of the Federal Land Managers) no later than 30 days after the end of each calendar year which shall contain the amount of sulfur dioxide emitted from the DREF; amount, facility, location of facility, vintage of Allowances retired; proof that Allowances have been transferred into account #XXX; and any applicable serial or other identification associated with the retired Allowances.

Additional Air Quality Mitigation
If Sithe chooses Option A, it will contribute $300,000 annually toward environmental improvement projects that would benefit the area affected by emissions from DREF, including the Class I areas and the Navajo Nation. If Sithe chooses Option B, it will contribute toward environmental improvement projects an amount equal to the $3 million cap described under Option B above, minus the cost of the Mitigation Allowances, up to a maximum of $300,000. Appropriate projects will be determined jointly by the Federal Land Managers, Navajo Nation EPA, the Desert Rock Project Company and Diné Power Authority, and may include projects that would reduce or prevent air pollution or greenhouse gases, purchasing and retiring additional emission reduction credits or allowances, or other studies that would provide a foundation for air quality management programs. Up to 1/5 of the contributions can be dedicated to air quality management programs. The remaining contributions shall be used to support projects that mitigate greenhouse gas emissions or criteria pollutants impacts. The Desert Rock Project Company shall have the ability to bank the emission reduction credits achieved through these projects and be entitled to these credits to comply with future greenhouse gas emission mitigation programs. Mitigation and contributions toward environmental improvement projects shall not occur before operation of the Desert Rock Energy project begins.

And,

Sithe will reduce mercury emissions by a minimum of 80% on an annual average using the air pollution control technologies as proposed in the permit application, i.e. SCR, wet FGD, hydrated lime injection, and baghouse. In addition, Sithe will raise the mercury control efficiency to a minimum of 90% provided that the incremental cost effectiveness of the additional controls (such as activated carbon injection or other mercury control technologies) does not exceed $13,000/lb of incremental mercury removed. Compliance with this provision will be determined by installation and operation of an EPA-approved mercury monitoring and/or testing program. In operating periods when a minimum of 80% mercury control (or 90% as noted above) is not technically feasible due to extreme low mercury concentrations in the burned coal, Sithe will work with EPA to establish a stack mercury emission limit in lieu of a percent reduction, for the purposes of demonstrating compliance.

Examples of Mitigation Strategies

Example #1:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option A, Sithe would be required to reduce SO_2 emissions at another source (or sources) within 300 km by 3,300 tons. These credits can be used to meet the requirements of the acid rain program under Title IV of the Federal Clean Air Act provided that the physical and/or operational change occur on one or more EGUs.

Example #2:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option A, suppose Sithe reduces SO_2 emissions at another source (or sources) within 300 km by 4,000 tons. In this case, Sithe would have created 700 tons of surplus SO_2 Emission Reduction Credits that it may use as it sees fit.

Example #3:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option B, Sithe would purchase its "regular" 3,000 tons of Title IV Allowances from any source, anywhere, plus up to 3,000 tons of SO_2 "Mitigation Allowances" from another source (or sources) within 300 km, provided that the total cost of the "Mitigation Allowances" does not exceed $3 million (in 2006 dollars). If each "Mitigation Allowance" costs at least $1,000, Sithe would be done.

Example #4:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option B, Sithe would purchase its "regular" 3,000 tons of Title IV Allowances from one or more EGU sources. For the remaining 3000 SO2 "Mitigation Allowances", Sithe may choose, as an option, to obtain 9000 NOx emission reduction credits from physical or operational changes of one or more NOx emission sources within 300 km.

Example #5:
Suppose Sithe obtains the necessary SO_2 reductions through a capital investment project (Option A), or purchases SO_2 Mitigation Allowances (Option B) at a cost of $2.7 million or less. Sithe would then contribute the maximum $300,000 to the environmental improvement fund because the total annual costs (allowances plus contribution) would be below the $3 million cap. On the other hand, if the mitigation allowances cost more than $2.7 million, Sithe would contribute the difference between the $3 million cap and the actual cost of the Mitigation Allowances (i.e., if allowance costs equal $2.9 million, the environmental improvement fund contribution would be $100,000).

Implementation
The clearest way for these measures to be implemented would be to include them in the PSD permit. Since EPA Region 9 is the permitting authority in this case, that agency would be responsible for including the measure in the permit. Absent including the measures in the permit, other ways of ensuring the mitigation measure will take place are being explored. The FLMs prefer that the mitigation measures be federally enforceable regardless of the mechanism ultimately used.

III. Feasibility of the option
By agreeing to the mitigation measures, Sithe has implicitly affirmed the feasibility of the measures. Incorporation into a permit is feasible for the permitting authority as long as the measure does not contradict any statutory or regulatory provision.

Background Data and Assumptions
The suggested mitigation measures are taken from the agreement-in-principle between Sithe Global Power and the FLMs. Estimated emissions from DREF come from the draft permit.

V. Any uncertainty associated with the option
The uncertainty in this option involves how stakeholders can be assured the measures will actually happen.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

Citations:
[1] References to Sithe include its subsidiary "Desert Rock Energy Company, LLC" which will be the owner of DREF (referred to herein as the Desert Rock Project Company).
[2] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining emission reductions, Sithe may obtain real emission reductions at sources other than EGUs.

[3] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining and tracking emission reductions, nitrogen oxides reductions may be substituted for sulfur dioxide reductions by a ratio of three tons of nitrogen oxides to one ton of sulfur dioxide.
[4] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining emission reductions, Sithe may obtain physical emission reductions at sources not granted allowances under 40 CFR 73.
[5] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining and tracking Emission Reduction Credits, Sithe may obtain real emission reductions at sources other than EGUs. Nitrogen oxides reductions may be substituted for sulfur dioxide reductions by a ratio of three tons of nitrogen oxides to one ton of sulfur dioxide.
[6] All costs referenced in this document are base-year 2006 dollars that will be adjusted for inflation by using the consumer price index.

FUTURE POWER PLANTS

Mitigation Option: Integrated Gasification Combined Cycle (IGCC)

I. Description of the mitigation option

Energy related projects in the Greater Four Corners Region (NM, CO, AZ, UT and WY) are expected to continue to grow at or above current rates. Population and related commerce growth in the 12 county local Four Corners Region (NM, CO, AZ, UT) grew at a brisk rate of 23.8% during the 1990s (1). Future electric power demand will require new power plants and transmission grid capacities. Alternative future "clean coal" power generation technologies such as, FutureGen, Integrated Gasification Combined Cycle (IGCC), and advanced fossil fuel power plants (with carbon capture and sequestration (CCS) technologies) and renewable energy facilities (e.g., wind farms, solar arrays, …) will be needed to accommodate this growth, as well as the increasing demand outside the Four Corners area. Given the size of the western coal reserve and its relatively inexpensive cost compared to natural gas, commercial IGCC power plants could potentially play a role in meeting the region's future "clean" power needs.

Overview: A power plant based on IGCCtechnology combines or integrates a coal gasification system (gasifier and gas clean-up systems) with a highly efficient combined cycle power generation system. There are a variety of coal gasification technologies in various stages of development that are designed to produce clean synthesis gas (syngas) from coal. The combined cycle unit includes a gas turbine set consisting of a compressor, burner and the gas turbine coupled with a heat recovery steam generator (HRSG). The steam generated in the HRSG, as well as any excess steam generated in the gasification process that is not used elsewhere in the system, is used to power a steam turbine. An IGCC unit has the potential to achieve similar environmental benefits and thermal performance as a natural gas fired combined cycle power generation unit. The use of relatively low cost coal as a feedstock is the one of the main advantages of coal-based power plants. The ability of an IGCC unit to use coal while generating lower air emissions than conventional coal technologies has lead to increased interest in the technology. While IGCC is a promising technology, it has not completely commercially developed. Two small 260 MWe IGCC plants, the Wabash River Plant in Indiana and the Polk Plant in Florida, have been operating for over a decade. Originally built as demonstration plants, reliability of the IGCC units has generally improved over time with gasifier capacity factors in the range of 80% demonstrated in a number of years (2). (Note: the Polk Power Station IGCC unit has only had one year of operation where the gasifier CF was greater than 80% and two years where the CF was near 80% in the 10+ years of operation.) Currently there are at least five separate permit applications for commercial size IGCC plants in the continental United States. Four of these applications are for plants exceeding 600 MWe nominal capacity.

The operation of the major chemical and mechanical process components of a typical coal based IGCC power plant can be summarized as follows (3):

- The gasifier produces syngas by partially oxidizing coal in presence of air or oxygen.
- The ash in the coal is converted to inert, glassy slag.
- The syngas produced from the gasifier is cooled.
- The syngas is cleaned to remove particles.
- The slag and other inert material are collected to be used to make some products or can be safely discarded in the landfill.
- The mercury is removed by passing syngas through the bed of activated carbon.
- The sulfur removed from the syngas is converted into elemental sulfur or sulfuric acid for sale to chemical or fertilizer companies.
- The clean syngas can either be burned in a combustion turbine/electric generator to produce electricity or used as a feedstock for other marketable chemical products.

- Steam produced in the HRSG from the hot combustion turbine exhaust, as well as additional steam that has been generated throughout the process, drives a steam turbine to produce additional electricity.
- The stream exhausted from the steam turbine is cooled and condensed back to water. The water is then pumped back into the steam generation cycle.

Benefits:

- For traditional pollutants such as nitrogen oxides (NOx), sulfur dioxide (SO_2), particulate matter (PM) and mercury (Hg), IGCC is lower polluting than the current generation of traditional coal-fired power plants. It is potentially as "clean" a NOx emitter (< 0.3 lb/MW-hr) as for NGCC plants (4).
- The removal of sulfur compounds, particulates and mercury is more efficient in an IGCC because the removal can take place before the gas is burned (fuel gas) instead of removing the compounds from the exhaust gases following combustion (flue gas).
- The water requirement for the IGCC process is approximately one-third less than that of a pulverized coal plant.
- Solid waste generation at an IGCC power plant is less than that of a PC plant.
- IGCC plants are more flexible in terms of fuel feedstock because they can utilize a variety of fuels, such as coal, biomass, and refinery by-products such as petroleum coke (petcoke). In general, IGCC units are designed to use only one type of coal (i.e. bituminous, sub-bituminous or lignite), but can handle a variety of coals from within the same coal type.
- The CO_2 emissions from an IGCC unit can be higher than from a conventional coal power plant (3). However, based on current technology, it is believed that capture of CO_2 emissions from IGCC plants would be more energy efficient than capture from a conventional coal fired power plant.
- IGCC plants operate at efficiencies of about 40% but have the potential to be as high as 45% (or higher if fuel cells are used). By comparison, conventional combustion-based power plants have efficiencies that range from about 33% to 43%.

Burdens (or deployment barriers):

- General lack of commercial-scale operating experience, especially at Four Corners altitudes.
- Doubts about plant financial viability without subsidies. IGCC has significantly higher capital costs, nominally approximately 20% or higher than the cost for conventional PC plants (Wayland, 2006).
- Low plant reliability, demonstration of commercial plant reliability and capacity factor remains a concern.
- Without carbon capture, an IGCC can have a higher carbon footprint compared to a conventional PC plant. However, the lower total gas flow, the higher percentage of CO_2 in the gas stream, combined with the high operating pressure of the gas stream, makes it easier to recover CO_2 from the syngas in IGCC power plants than from flue gas in conventional coal power plants, based on current technology.
- IGCC carbon capture and sequestration (CCS) technologies have not yet been demonstrated at commercial scale. However, once CCS is demonstrated, IGCC has a potential advantage in capturing and sequestrating CO_2 at lower costs for the reasons stated in the bullet above.

II. Description of how to implement

A. Mandatory or voluntary

Voluntary to look at IGCC as a future clean power generation option for future power plants in the Four Corners area.

B. Indicate the most appropriate agency(ies) to implement

Policy options for use of Integrated Gasification Combined Cycle Technology could be developed by Environmental Protection Agency (EPA), Department on Energy (DOE), State or Tribal Environmental Protection Agencies.

III. Feasibility of the option

A. Technical: There is some concern about the feasibility of IGCC power plants at high altitude, elevated temperatures and using western fuels. High altitudes and elevated temperatures lead to significant derations of the power output from the gas turbine portion of the IGCC unit. Turbine manufacturers are working on ways to overcome this altitude deration but, to-date, no solutions have been developed and/or demonstrated.

Carbon dioxide capture technology from IGCC units is still in its research and development phase. To be more cost competitive, a number of technology improvements will need to be made in IGCC plant design; including larger, higher pressure and lower cost quench gasifiers (6). In addition, new and improved gas turbines will be needed that enable air extraction across the operating range of ambient temperatures and with hydrogen firing (7).

Carbon capture and sequestration technologies have potential to substantially reduce carbon emissions into the atmosphere. However the given the current cost of carbon capture and sequestration technologies, it will not be viable solution without a carbon penalty. CO_2 sequestration is also a site-specific geological issue. Options to address this issue include:

- Locating the IGCC unit in an area suitable for geologic sequestration, EOR, EGR or ECBMR
- Pipe the captured CO_2 from an IGCC unit to an area suitable for geologic sequestration, EOR, EGR or ECBMR
- Gasify the coal close to an area suitable for geologic sequestration, EOR, EGR or ECBMR and then send the gas for the power production (although this option does not receive the efficiency benefits associated with a fully integrated IGCC unit).

Currently in the US there are two small IGCC plants, the Tampa Electric Polk Power Station in Florida and the Wabash River Coal Gasification Repowering Plant in Indiana, using coal to make electric power as the primary product. These plants were funded and built in the mid-1990s as demonstration plants by DOE. Recently, however, five companies have applied for and in few cases already received permits and at least five companies have announced plans or issued letters of intent to build and operate IGCC facilities in the US. American Electric Power is proposing to build two 629 MW power plants in Ohio and West Virginia – although the projects have been put on hold due to concerns over project cost escalation (as have several other utilities) (8). Xcel Energy is investigating building an IGCC plant with CO_2 capture and sequestration. Duke and Tampa Electric have received tax credits to help reduce the cost of building IGCC power plants under the Energy Policy Act of 2005.

B. Environmental: For traditional pollutants such as NOx, SO_2, PM and Hg, IGCC is inherently lower polluting than the current generation of traditional coal-fired power plants. There are a number of concerns related to the geologic sequestration of CO_2, whether or not the CO_2 is from an IGCC unit. These concerns include, but not limited to the following:

- How will geologic sequestration be permitted over the long-term, including demonstration studies and the duration of the sequestration permit (i.e. 5 year, life of facility, etc.)
- What measurement, monitoring and verification (MMV) techniques and requirements will be placed on the project
- How will the liability associated with the sequestered CO_2 be addressed
- How will the property rights associated with the sequestered CO_2 be addressed

- Will the injection of CO_2 into a deep saline aquifer prohibit the future use of water from that aquifer should in-land desalination prove to be cost-effective or necessary to address future water needs

C. Economic: IGCC has higher capital costs than conventional PC plants (9). Historically – and currently, concerns about operational reliability and costs presented issues of uncertainty for IGCC technology and impeded its deployment. IGCC can be a versatile technology and is capable of using a variety of feedstocks. In addition to various coal types, feedstocks can include petroleum coke, biomass and solid waste.

Along with electricity production, IGCC facilities, if designed to do so, can co-produce other commercially desirable products. Some of these products include steam, oxygen, hydrogen, fertilizer feed stocks and Fischer-Tropsch fuels (10).

There is not a consensus about the relative costs of carbon capture technology for various plants. General consensus is that, given current technology, it is less expensive to capture CO2 from IGCC plants than from any other coal-based plant, as well as NGCC plants (11). According to an MIT study, today the capital cost (in 1999 dollars?) of CO_2 capture and separation is $1730/kW, which will reduce to $1433/kW in 2012. The CO_2 capture and separation cost for a NGCC power plant is about $1120/kW today, which will reduce to $956/kW in 2012 (12). There are many uncertainties with regards to the costs of CCS.

The operational versatility noted above for IGCC technology may mitigate the risk of higher costs. In addition, under the Energy Policy Act of 2005, there are provisions for tax credits and a DOE Loan Guarantee Program to provide incentives to facilitate the deployment of IGCC technology.

IV. Background data and assumptions used:

(1) City of Farmington Draft Consolidated Plan, 2004, June
(2) Coal-Based IGCC Plants – Recent Operating Experience and Lessons Learned. Gasification Technologies Conference, Washington, DC (October 2006).
(3) Pioneering Gasification Plants (DOE): http://www.fe.doe.gov/programs/powersystems/gasification/gasificationpioneer.html
(4) Wayland, R.J., 2006, U.S. EPA's Clean Air Gasification Activities, Gasification Technologies Council, Winter Meeting January 26, Tucson, Arizona
(5) Blankinship, Steve. "Amid All the IGCC Talk, PC Remain the Go-To Guy." Power Engineering International.
(6) Revis, James, 2007, Clean Coal Technology Status: CO_2 Capture & Storage *Technology Briefing for COLORADO RURAL ELECTRIC ASSOCIATION, February 19*
(7) Wabash River IGCC Topical Report 2000 - www.fossil.energy.gov/programs/powersystems/publications/Clean_Coal_Topical_Reports/topical20.pdf
(8) American Electric Power permit application for proposed IGCC power plant in Great Bend, Ohio and Mountaineer, West Virginia. http://www.aep.com/about/igcc/technology.htm
(9) Technical Report on the Environmental Footprint and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, Fact Sheet: http://www.epa.gov/airmarkets/articles/IGCCfactsheet.html
(10) IGCC & CCS Background Document. 2006, State Clean Energy-Environment Technical Forum Integrated Gasification Combined Cycle (IGCC) Background and Technical Issues June 19
(11) Clayton, S.J., Stiegel, G.J., and Wimer, J.G., 2002, Gasification Technologies Product Team U.S. Department of EnergyU.S. DOE's Perspective on Long-Term Market Trends and R&D

Needs in Gasification 5th European Gasification Conference Gasification – The Clean Choice Noordwijk, The Netherlands April 8-10
(12) Herzog, Howard. "An Introduction to CO_2 Separation and Capture Technologies." MIT Energy Laboratory (1999).

V. Any uncertainty associated with the option (Low, Medium, High):
Medium to High, particularly when coupled with CCS as both are developing technologies.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups: None at this time.

Mitigation Option: Carbon (CO_2) Capture and Sequestration (CCS)

I. Description of the mitigation option

Carbon Capture and Sequestration (CCS) generally consists of removing carbon in the form of CO_2 from either the fuel gas stream; syngas of an Integrated Gasification Combined Cycle (IGCC) power plant or the flue gas stream of other fossil fuel power plants (i.e. pulverized coal, including supercritical pulverized coal (SCPC) and ultra-super critical pulverized coal (USCPC), and natural gas (NGCC) units) compressing and transporting the CO_2 to the sequestration site and sequestering the CO_2. Sequestration can consist of either injecting the CO_2 into a deep saline aquifers or using the CO_2 for enhanced oil recovery (EOR), enhanced natural gas recovery (EGR) or enhanced coal bed methane recovery (ECBMR). Utilization of CCS in combination with other mitigation options such as alternative fuels, energy efficiency and renewal energy would mitigate the potential greenhouse gas (GHG)/climate change impacts of using fossil fuels for power generation.

Overview:

Currently, there are two generic types of CO_2 removal solvents available:

- Chemical absorbents (i.e. amines) that react with the acid gases and require heat to reverse the reactions and release the CO_2
- Physical absorbents (i.e. Selexol and Rectisol) that dissolve CO_2

Amines: Amines are organic compounds that contain nitrogen as the key atom. Structurally, amines resemble ammonia. The advantage of an amine CO_2 removal system is that it has a lower capital cost than any of the current physical solvent processes. The disadvantage is that an amine system uses large amounts of steam heat for solvent regeneration and energy to re-cool the amine, making it a less energy efficient process.

Selexol: Selexol is the trade name for a physical solvent that is a mixture dimethyl ethers of polyethylene glycol. In the Selexol process, the solvent dissolves the CO_2 from the gas stream at a relatively high pressure, generally in the range of 300 – 1,000 psia. The resulting rich solvent can then either be let down in pressure and/or steam stripped to release and recover the CO_2. The Selexol process requires less energy than amine-based processes as long as the operating pressure is above 300 psia. At lower pressures, the amount of CO_2 that is absorbed per volume of solvent drops to a level that generally favors the use of an amine system.

Rectisol: Rectisol is the trade name for a CO_2 removal process that uses chilled methanol. In the process, methanol at a temperature of approximately –40 °F absorbs the CO_2 from the gas stream at a relatively high pressure, generally in the range of 400 – 1,000 psia. The resulting rich solvent can then either be let down in pressure and/or steam stripped to release and recover the CO_2. While the methanol solvent is less expensive than the Selexol solvent, the Rectisol process is more complex, has a higher capital cost and requires costly refrigeration to maintain the low temperatures required. It does, however, provide for the most complete removal of CO_2.

Cryogenic coolers are also currently shown to capture CO2 from the combustion exhaust. The cost of CO2 capture is generally estimated as three fourth of the whole carbon capture, storage, transport, and sequestration system. Currently the average cost of carbon capture is about $150/ton by using current technology is high for carbon emission reduction purposes (1). In order to transport and sequester the CO_2, the gas must be compressed to 2000 psia or higher. Research is underway to find better technologies for carbon capture. Presently, the most likely identifiable options apart from absorbents for the carbon separation and capture are (1):

- Adsorption (Physical and Chemical)
- Low-temperature Distillation
- Gas separation Membranes
- Mineralization and Biomineralization

Benefits:

- CO_2 that would otherwise be emitted to the atmosphere is sequestered.
- If used for Enhanced Oil Recovery (EOR), Enhanced Gas Recovery (EGR) or Enhanced Coal Bed Methane Recovery (ECBMR), the CO_2 from power plants is put to beneficial use and could replace some or all of the natural CO_2 that is currently used for those purposes as well as recover fossil fuel.

Burdens (or deployment barriers):

- Currently there are no power plants in the world that perform CCS, so the integration of the power plant technology with the CCS technology has yet to be proven.
- The capital and O&M costs for CCS are significant and adversely impact the cost of electricity (COE). The cost of electricity will increase by 2.5 cents to 4 cents/Kwh if current carbon capture technologies are added to electrical generation(1).
- No large-scale tests of deep saline aquifer injection have been performed to-date. The Sleipner project in Norway's North Sea is the world's first commercial carbon dioxide capture and storage project(2). CO2 is extracted from gas production on Statoil's Sleipner West Field in the Norwegian North Sea. Started in 1996, it sequesters about 2800 tons of carbon dioxide each day and injects into Utsira sandstone formation (aquifier)(3).
- No environmental laws, rules or procedures are in place for CCS projects.

II. Description of how to implement

A. Mandatory or voluntary

Voluntary in the near term; mandatory as laws, rules and procedures are established.

B. Indicate the most appropriate agency(ies) to implement

Environmental Protection Agency (EPA), Department on Energy (DOE), State Environmental Protection Agencies.

III. Feasibility of the option

A. Technical:

IGCC

In IGCC power plants, CO_2 can be captured from the synthesis gas after the gasification process before it is mixed with air in a combustion turbine. The CO_2 is relatively concentrated (50 volume %) and at high pressure which provides the opportunity for lower cost for carbon capture (4).

While proven carbon capture technology is available for IGCC plants, there are currently no IGCC facilities in the world that capture, compress and sequester CO_2. Depending on the IGCC technology and the carbon capture technology used, it is estimated that carbon capture and compression could add 35 - 50% to the capital cost of the plant and the cost of electricity. These costs do not include the costs for installation of wells and/or pipelines for sequestration of the captured and compressed CO_2, both from a demonstration (pre-permitting) and ongoing operations perspective.

A number of IGCC technology vendors are working on improvements to their gasifiers that allow for easier CO_2 capture at reduced capital and O&M cost. In addition, a number of firms are working on improved CO_2 capture systems, with most efforts in the area of enhanced or advanced amine systems. It is too early in the development process to verify or quantify the potential cost and performance benefits of these new design efforts.

Another concern is the fact that there is currently no large combustion turbine commercially available that is capable of burning the hydrogen rich gas that would result from an IGCC plant with CCS.

SCPC/USCPC
While proven carbon capture technology is available for SCPC/USCPC plants (currently limited to amine systems), there are currently no SCPC/USCPC facilities in the world that perform CCS. Depending on the carbon capture technology used, it is estimated that carbon capture and compression could add 65 - 100% to the capital cost of the plant and the cost of electricity. These costs do not include the costs for installation of wells and/or pipelines for sequestration of the captured and compressed CO_2.

A number of projects are currently underway to try to improve the capture of CO_2 from SCPC/USCPC units in terms of removal efficiency and capital and O&M expenditures. Generally, these projects are targeting 90% capture of CO_2, although there is a general belief that the optimal/achievable reduction level will be less. EPRI and Alstom are working on a chilled ammonia (chemical absorbent) system. A 5 MW slipstream chilled ammonia pilot system will go into operation in Wisconsin in the fall of 2007. According to EPRI, the goal for the project is to reduce the cost for CO2 capture and compression by approximately 66% versus the cost of conventional amine systems. While the exact costs and efficiency gains of the chilled ammonia system are not known at this time, it is known that the system efficiency will decrease in warmer climates.

Babcock & Wilcox (B&W) is currently working on a design for a 500 MW oxygen fired, recirculating gas stream (oxy-fired) boiler for Sask Power in Canada. This unit would use oxygen from an air separation unit (ASU) instead of air for combustion. This use of oxygen means that less NOx is formed (approximately 65% less) in the combustion process and that the resulting flue gas is mainly CO_2 (up to approximately 80%). The flue gas stream, after removal of particulates, SO_2 and moisture, would be recirculated through the boiler, removing a portion (20 - 35%) of the CO_2 with each pass. B&W expects to start testing the design at their 30 MW Clean Environment Development Facility (CEDF) in Alliance, Ohio in June of 2007. Net power output before CCS from the 500 MW unit is expected to be on the order of 350 MW. Additional power will be required to compress and sequester the captured CO_2.

In addition, a number of vendors are working on enhanced/advanced amine systems that they believe will outperform current amine systems.

NGCC
While carbon capture technology is available for NGCC plants (currently limited to amine systems), there are currently no NGCC facilities in the world that perform CCS. Depending on the carbon capture technology used, it is estimated that carbon capture and compression could add 40 - 80% to the capital cost of the plant and the cost of electricity. These costs do not include the costs for installation of wells and/or pipelines for sequestration of the captured and compressed CO_2.
B. Environmental: There are currently no environmental laws, rules or procedures in place for CCS projects. Issues that need to be addressed include, but are not limited to:

- How will geologic sequestration be permitted over the long-term, including demonstration studies and the duration of the sequestration permit (i.e. 5 year, life of facility, etc.)
- What measurement, monitoring and verification (MMV) techniques and requirements will be placed on the project
- How will the liability associated with the sequestered CO_2 be addressed
- How will the property rights issues associated with the sequestered CO_2 be addressed
- Will the injection of CO_2 into a deep saline aquifer prohibit the future use of water from that aquifer should in-land desalination prove to be cost-effective or necessary to address future water needs

C. Economic: The capital and O&M impacts of CCS are significant and will result in substantial increases in the cost of electricity.

IV. Background data and assumptions used:

1) Carbon Capture Research. U.S. Department of Energy
<http://www.fossil.energy.gov/programs/sequestration/capture/>
2)Carbon Capture and Sequestration Technologies, MIT.
<http://sequestration.mit.edu/>
3) Carbon Dioxide storage prized. STATOIL.
<http://www.statoil.com/statoilcom/SVG00990.NSF?OpenDatabase&artid=01A5A730136900A3412569B90069E947>
4) Carbon Sequestration. National Energy Technology Laboratory.
<http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html>

V. Any uncertainty associated with the option (Low, Medium, High)

High, as the integration of power generation and CCS is a developing and undemonstrated technology and there are currently no laws, rules and procedures are established to address CCS.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups: None at this time.

Mitigation Option: Negotiated Agreements in Prevention of Significant Deterioration (PSD) Permits

<u>I. Description of option</u>

Summary of Option

Agreements regarding mitigation of air quality and air quality related value impacts negotiated between PSD permit applicants and parties other than the permitting authority should be incorporated into the PSD permit and made federally enforceable. If the other party is a federal land manager, there should not have to be a formal declaration of adverse impact before the agreement is made part of the permit.

Background

A primary goal of the PSD program is to protect air quality and air quality related values in areas that attain the National Ambient Air Quality Standards, specifically certain National Parks and Wilderness areas (i.e., "Class I" areas). If representatives of a proposed new source are willing to mitigate the predicted impacts of the new facility, then the permitting authority should honor this intent to reduce air pollution impacts at Class I areas by including mitigation measures in a PSD permit.

This issue arose in the context of federal land manager (FLM) review of the Desert Rock Energy Facility permit application. Federal land managers responsible for "Class I" areas are responsible for reviewing PSD permit applications for new sources to determine if that source would cause or contribute to an adverse impact on visibility or other air quality related values. In the immediate Four Corners area, Mesa Verde National Park and Wemminuche Wilderness Area are the closest Class I areas, and would be impacted the greatest by the Desert Rock Energy Facility. However, there are a total of 15 Class I areas that could be impacted by the facility.

Typically, FLMs address potential adverse impacts through consultation with the permit applicant and permitting authority before the permit is proposed, and before any formal adverse impact finding. When it becomes apparent through the modeling analysis that a facility *may* have an adverse impact, applicants are generally willing, and actually prefer, to discuss changes to address those adverse impacts, through tightening down the control technology, obtaining emission offsets, or other methods. State permitting agencies have generally incorporated the agreed-upon mitigation measures directly into the PSD permit, which as a practical matter, makes those agreements enforceable. This process allows for consultation in the case of suspected adverse impacts and avoids delays in permitting or denial of a permit, which may result from a formal finding of adverse impact.

The permitting authority for the Desert Rock Energy Facility is the Environmental Protection Agency (EPA) Region 9, because the facility would be located on the Navajo Reservation, where neither the State of New Mexico (or Arizona) nor the Navajo Nation have permitting authority. For over two years, the National Park Service and the U.S. Forest Service worked closely with Desert Rock representatives, EPA and tribal representatives to ensure the potential impact of the proposed facility were carefully analyzed. When it became evident that emissions from the facility could adversely impact visibility in several Class I areas, the energy company suggested mitigation measures intended to produce a net environmental improvement in the area, notwithstanding construction and operation of the Desert Rocky Energy Facility. Negotiations ensued and resulted in an agreement in principle on substantive mitigation measures in April of 2006. In July, 2006, EPA issued a proposed PSD permit for the facility but did not include the agreed-upon mitigation measures. EPA reasoned that mitigation measures should not be included as part of the permit absent a formal declaration of adverse impact by the FLM.

Without the terms of the agreement in principle included as part of the PSD permit, there is no mutually acceptable way to ensure the specific mitigation measures will be enforceable, and therefore, no assurance that adverse impacts to air quality related values in Class I areas will be avoided throughout the life of the facility.

It is unacceptable that the EPA, in July 2006, issued a proposed PSD permit for the facility but did not include the agreed upon visibility mitigation measures. The so called brown curtain of "regional haze" already present which blankets the Four Corners Area blocks visibility. Not only is it ugly, it indicates degradation of the air quality. Visibility mitigation must be enforceable; therefore, visibility measures must be included in the permitting of Desert Rock and any other future coal fired power plants in the Four Corners Area.

II. Description of how to implement

The permitting authority for a given facility would be responsible for including any agreed-upon mitigation measures into a PSD permit. Usually the permitting authority is the state agency responsible for air pollution control; in some cases, however, the EPA is the permitting authority.

Regarding the actual negotiation of any mitigation measures, information regarding the mitigation measure and its effects is exchanged in the permitting process. In some instances the applicant may supply additional information in the form of an air quality modeling analysis and/or control technology analysis to demonstrate to the FLM the effectiveness of the mitigation measures in reducing impacts to AQRVs at the Class I area(s) in question.

III. Feasibility of the option

By agreeing to a mitigation measure, a permit applicant has implicitly affirmed the feasibility of the measure. Incorporation into a permit is feasible for the permitting authority as long as the measure does not contradict any statutory or regulatory provision.

IV. Background data and assumptions used

The PSD program is created at 42 U.S.C. §§7470-7492; implementing regulations are codified at 40 C.F.R. §51.166 and 40 C.F.R. §52.21.

V. Any uncertainty associated with the option

No uncertainties known.

VI. Level of agreement within the work group for this mitigation option

To Be Determined

VII. Cross-over issues to the other Task Force work groups

None

Mitigation Option: Clean Coal Technology Public Education Program

I. Description of the mitigation option

The goal of this option is to educate all stakeholders, particularly the wider public, as to the cost/benefits of the latest clean coal technology during the permitting process for new coal based power generation facilities in the Four Corners. The public who then participates in the hearings and other steps of the permitting process, would be educated and know the pros and cons of the various technological options available to those proposing the project.

According to the Department of Energy, coal will continue indefinitely to be one of the least expensive sources of electric power in the United States. The Four Corners region has abundant coal resources and many stakeholders who wish to capitalize on that abundance to produce energy, jobs and revenue. Technologies for transforming coal to energy vary enormously in cost, and pollution, including release of global warming gases. Research into improved (cleaner) technologies continues, see President Bush's new commitment to the Clean Coal Power Initiative as one example. The public in the Four Corners area needs to be informed and frequently updated as to the status of research and testing in clean coal technology so they can ask educated questions and make educated political decisions and/or demands on policy-makers in the agencies permitting power generation installations in the Four Corners area. This mitigation option lays out a plan for the on-going education of Four Corners stakeholders with regard to the latest, cleanest, safest technologies for converting our generous resource into energy.

This option would require the primary permitting agency for a proposed project to designate early in the process a non-political 'clean coal technology scientist/advocate' whose responsibility it would be to prepare documentation in layman's terms on the latest research and feasibility of clean coal technology and where the proposed technology stands in relation to the current ideal. This individual would make presentations at hearings, be available by phone/internet for consultation with stakeholders, including the media, submit factual information pieces to the Four Corners media on clean coal technology, speak at community meetings, etc. In other words, the scientist/advocate would design and conduct an extensive public relations campaign to education the public during the permitting process.

Many institutions, including the Department of Energy, and educational institutions, conduct research in clean coal technology on an ongoing basis and NGOs like San Juan Citizens Alliance make themselves experts on the issues and could be called upon to educate the public at any given point. The obstacle here is how to ensure that the latest knowledge reaches the lay public when they can use it during the permitting process of new coal-based power plants and/or updates of older units. One way is to tie public education into the EPA permitting process. (Other ideas are welcome.) This option places an additional burden on the EPA in time, energy and cost and therefore indirectly on those proposing the new or updated power plants on to whom the additional costs of this step would be passed.

Participation of an educated public in the permitting process will lead to better long-term decision-making for the Four Corners area.

II. Description of how to implement

A. Mandatory or voluntary:
Mandatory

B. Indicate the most appropriate agency(ies) to implement:

The lead permitting agency, typically the EPA. The Department of Energy might be another appropriate agency; however, it is hard to envision how they could be motivated enough to know when and where their expertise is needed if not tied to the permitting process.

EPA is strongly encouraging companies proposing to build to power plants to meet with the local citizens in nearby communities and regional areas to discuss their plans including their projected emissions if the facility has been announced. In addition, if they are constructing near a non-attainment area for any pollutant, EPA believes it is important to meet with local air planning officials in the non-attainment area. The companies need to be willing to lay everything on the table with respect to technology, emissions, and comparisons to other similar facilities nationwide. The companies are better off actually doing these types of meetings before they even send in the permit application. Oftentimes, people are not opposed to a new cleaner EGU, but they want something done about those older existing units in the area. This hopefully will help educate the community on what the company would like to construct.

Remember once the permitting application arrives and the State proposes the permit for public comment.....some State regulatory requirements may require them to treat any meeting where comments are made about the facility's proposed permit and technology into the public record. Therefore, it would be encouraged that any meetings with the community to occur prior to the permit being public noticed.

Another option for sponsoring a Clean Coal meeting in the 4 Corners area is to invite speakers from Dept. of Energy, EPA, National Labs doing coal related work, and State permitting officials. It would also be okay to invite independent experts. Obviously, the issue becomes funding for such a meeting. Generally, a DOE and/or EPA rep will not cost you anything. Many technology vendors know the clean coal technology in depth and would participate.

Another option is to talk to state Air Quality Bureau chief about applying for special projects funds from EPA to host such an event in the future. It is not certain what type of funds DOE may have available, but they may have funding for such a meeting as well. Another option is for a company to fund as part of an enforcement settlement agreement, or for a consortium of the mining companies and power utilities to fund the meeting location, but the State to do all of the planning and agenda development for the meeting.

It would be strongly encouraged that the state environment department go through the actual permitting process at any meeting clearly showing in a process flowchart the specific points for public comment opportunities since it would be the state process that they would be following. The state environment department also needs to educate the public on the types of comments that actually are considered valid or significant comments.....(examples are great) versus the general "not in my backyard" comments.

Options for on funding, implementation, and a CCT public educational program within existing state PSD permitting programs:

- **Establish a federal/state agency MOU**: A memorandum of understanding (MOU) would provide a mechanism for CCT public information transfer during the PSD permit application. It could facilitate the selection of an independent engineer/ scientist on clean coal technology from nearby leading universities such as Colorado School of Mines or from independent national labs such as National Energy Technology Laboratory or from reputable CCT research non-for profit scientific institution such as Union of Concerned Scientists. The engineer/scientist would provide the public with status on CCT research/demonstration/commercialization as well as comparative advantages or disadvantages of these technologies with the proposed power plant technology (e.g., SCPC plant).
- **Develop and maintain a CCT education/information transfer web-portal**: New commercial power generation technological advancement occur over a relatively long time frame. An easily accessible and updatable source of CCT information and educational material can be provided through a web portal. Argonne has developed a variety of energy web portals, many with public

outreach and some with educational elements (http://ocsenergy.anl.gov/, http://www.onlakepartners.org/). A web based outreach platform can provide CCT educational material on demand in layperson language and can provide public outreach tools for more informed and effective public involvement. Advancements in the clean coal technology could be updated on a regular basis. The state permitting agency could assume web-portal maintenance with an option for independent oversight and feedback from CCT experts. These experts (an engineer/scientist) can be retained to further support these efforts in person at public meetings during breakout public CCT education sessions.

III. Feasibility of the option

A. Technical:
Feasible, these people exist in the Four Corners area; Bill Green is an example of one. The Department of Energy undoubtedly could recommend local or regional experts.

B. Environmental:
Not relevant, no impact

C. Economic:
Retaining such a scientist/advocate will cost money but the reasonable expenses for this individual could be passed by the permitting agency to the organizers of the proposed power generation facility

This may require a regulatory and fee changes by state agencies......include a requirement for such a meeting in the State rules including a fee requirement for the permit applicant to fund the meeting location/facility to host such a meeting in the Regional area of the proposed facility. It would need to be researched and discussed to ensure that it's not prohibited by the CAA.

The ideas for funding of clean coal technology education program (within existing state PSD permitting programs):

- To implement such an effective clean coal technology education program a funding mechanism needs to be worked out between states and EPA. Options include but are not limited to:
  - The permitting fee for the power plan can be increased in order to pay for the the public education outreach program (e.g., web-portal and/or CCT expert).
  - Some non-for profit foundation involved in public education can be contacted to obtain a grant to build the webportal as well as pay for the compensation to experts/scientists.
  - It may be possible to find independent experts/scientists who will be able to provide their time for free for public good but there will still be a need of compensation for travel and lodging.

D. Political:
There is likely to be political resistance to spending additional dollars in this way. Additionally, the effort to educate the public on clean coal technology should be on ongoing effort, not dependent on proposal of power plants; however, it is difficult to figure out how to tie such an independent effort to the motivation and funding that it would take to get it to actually happen.

IV. Background data and assumptions used

Assumptions:
1. Coal continues to be abundant in the Four Corners area and in demand in power generation facilities
2. Stakeholders continue to desire to construct power generation facilities in the Four Corners area using coal, as opposed to transporting it out to other areas for use.
3. A standardized cost-effective perfectly clean technology for use of coal in power generation is years away.

V. Any uncertainty associated with the option (Low, Medium, High)
The only uncertainty that exists involves the degree of success the scientist/advocate would have in educating the public given the apathy sometimes exhibited by the public around these issues

VI. Level of agreement within the work group for this mitigation option
VII. Cross-over issues to the other Task Force work groups

Mitigation Option: Utility-Scale Photovoltaic Plants

I. Description of the mitigation option

Future Large-scale photovoltaic power plants (solar energy plants) could be built to accommodate future energy demands and offset some of the current coal-based coal fired power demands

Large-scale Photovoltaic power plants would consist of many PV arrays working together. PV electricity generation does not consume fuel and produces no air or water pollution.

The Electric Power Research Institute (EPRI) announced in July 2007 the beginning of a new project to study the feasibility of concentrating solar power in New Mexico. Unlike conventional flat-plate solar or photovoltaic panels, concentrating solar power (CSP) uses reflectors to concentrate the heat and generate electricity more efficiently. There are four utility-sized CSP plants in the U.S. today; one in Nevada and three in California. Initiated by New Mexico utility PNM and with subsequent interest from other regional utilities, the project will be directed and managed by EPRI. PNM has expressed interest in building a CSP plant in New Mexico by 2010. The feasibility study for a power plant of the 50-500 megawatt (MW) size range is expected to be finished by the end of 2007. The Four Corners area is one of the best areas for solar energy production in the United States and would be an ideal location for a new solar energy plant. For example, in Farmington, NM a flat-plate collector on a fixed-mount facing south at a fixed tilt equal to latitude, sees an avg. of 6.3 hours of full sun. The solar plant could help New Mexico meet renewable energy portfolio standards. San Juan County also has a renewable energy school focusing on solar energy system design and installation. The plant could potentially be an educational/technical resource for the college.

Benefits:

- Utilities can build PV plants much more quickly than they can build conventional fossil or nuclear power plants, because PV arrays are fairly easy to install and connect
- Unlike conventional power plants, modular PV plants can be expanded incrementally as demand increases
- Utilities can build PV power plants where they're most needed in the grid, because siting PV arrays is usually much easier than siting a conventional power plant
- Solar energy is clean energy and uses the sun for fuel.

Tradeoffs:
Burdens:

- Photovoltaic systems produce power only during daylight hours, and their output thus can vary with the weather. Utility planners must therefore treat a PV power plant differently than they would treat a conventional plant.
- Using current utility accounting practices, PV-generated electricity still costs more than electricity generated by conventional plants in most places, and regulatory agencies require most utilities to supply the lowest-cost electricity

II. Description of how to implement

A. Mandatory or voluntary

Mandatory (could be added as part of Renewable Energy Portfolio system)

May become more cost effective and implemented voluntarily as the technology continues to mature and power generation stakeholders see economic advantages to solar power.

B. Indicate the most appropriate agency(ies) to implement

State and Federal Governments can pass legislation requiring larger Renewable Energy Portfolios

III. Feasibility of the option

A. Technical –
PV Technology is available and technically feasible

B. Environmental –
PV systems have little adverse environmental impact

C. Economic –
Cost of PV systems to generate power is still more expensive than conventional fossil-fuels

DOE, the Electric Power Research Institute, and several utilities have formed a joint venture called *Photovoltaics for Utility-Scale Applications* (PVUSA). This project operates three pilot test stations in different parts of the country for utility-scale PV systems. The pilot projects allow utilities to experiment with newly developing PV technologies with little financial risk.

IV. Background data and assumptions used

1. DOE Energy Efficiency and Renewable Energy, Solar Energy Technologies Program http://www1.eere.energy.gov/solar/utility_scale.html

2. PVUSA Solar: a Renewable Ventures Project, http://www.pvusasolar.com/

V. Any uncertainty associated with the option:

VI. Level of agreement within the work group for this mitigation option: To Be Determined.

VII. Cross-over issues to the other Task Force work groups

Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

Mitigation Option: Biomass Power Generation

I. Description of the mitigation option

Power Generation using biomass fuels can potentially reduce net CO_2 emissions and other criteria pollutants from 4 Corners area power generation if displacing traditional coal-fired generation and is an option for future power plants in the area. Power from biomass is a proven commercial electricity generation option in the United States. With about 9,733 megawatts (MW) in 2002 of installed capacity, biomass is the single largest source of non-hydro renewable electricity. [1, 2]

Biomass used for energy purposes includes: Leftover materials from the wood products industry, Wood residues from municipalities and industry, Forest debris and thinnings, Agricultural residues, Fast-growing trees and crops, Animal manures. [2]

An aggressive Renewable Portfolio Standard was set in the 2007 NM legislative session. It includes 20% of power generation from renewables by 2020 (for large utilities) and 10% by 2020 (for rural electric cooperatives).
Biomass may be a necessary part of power generation to meet these standards.

In addition a 2005 executive order outlined Greenhouse Gas Emission Reduction Targets. These included reductions of NM Greenhouse gases to 2000 levels by 2012. Biomass power generation may be an alternative source of energy that can offset some of the CO_2 emissions from fossil fuel-based combustion.

Benefits

Biomass combustion to produce electricity generates negligible Sulfur Dioxide and it has been shown to produce less Nitrogen Oxide emissions than coal-fired combustion. CO_2 is absorbed during biomass growth cycle in photosynthesis and then released during combustion, so the direct combustion of the biomass feedstock can be considered to have a net 0 effect on CO_2 emissions. If the biomass fuel can be planted, matured, and harvested in shorter periods of time compare to the natural growth plants then the recycling of CO_2 in the environment can be reduced to close to one – third.

Other benefits include rural economic growth, increased national energy security, and using waste products that would otherwise have to be disposed. Using biomass fuel to generate electricity will reduce the greenhouse gas methane in the environment because if discarded in the landfill, the decomposition of biomass fuel generates methane.

Tradeoffs

- Land required for growing biomass.
- Higher nitrogen content of biomass fuel can contribute to higher NO_x emission such as in the case of fertilizer used to grow biomass fuel.
- N_2O emissions from fertilizer to grow biomass, if used.
- Energy emissions to grow, collect, and transport biomass fuel to plant
- Vehicle and dust emissions from transport trucks
- Energy emissions to dispose of waste
- The particulate emission from the biomass power generating power plant is a real concern. However the particulate emission can be controlled using readily available PM control technologies.

Burdens

For biomass to be economical as a fuel for electricity, the source of biomass must be located near to where it is used for power generation. This reduces transportation costs — the preferred system has transportation distances less than 100 miles.[3]

II. Description of how to implement

A. Mandatory or voluntary

Voluntary. Biomass may offset some of the coal based power generation.
May be necessary under new Renewable Portfolio Standard requirements for New Mexico & Colorado

B. Indicate the most appropriate agency(ies) to implement

Industry Research and Development, State and Federal Policy Support

III. Feasibility of the option

A. Technical – Biomass power generation is a proven commercial technology. Co-firing with fossil fuels may be the most feasible option at this time

B. Environmental – Biomass power generation has some significant advantages over fossil-fuel power generation. As demonstrated by some of the public hearings and objections to a new 35-megawatt plant, proposed to be built in Estancia, NM by Western Water and Power Production LLC., biomass may be a challenging technology to implement.

C. Economic –

A typical coal-fueled power plant produces power for about $0.023/kilowatt-hour (kWh). Cofiring inexpensive biomass fuels can reduce this cost to $0.021/kWh, while the cost of generation would be increased if biomass fuels were obtained at prices at or above the power plant's coal prices. In today's direct-fired biomass power plants, generation costs are about $0.09/kWh. In the future, advanced technologies such as gasification-based systems could generate power for as little as $0.05/kWh. For comparison, a new combined-cycle power plant using natural gas can generate electricity for about $0.04-$0.05/kWh at fall 2000 gas prices.[3]

IV. Background data and assumptions used

1. US DOE Energy Efficiency and Renewable Energy, Biomass Program
http://www1.eere.energy.gov/biomass/technologies.html

2. EIA RENEWABLE ENERGY 2002,
http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/table5.html]

3. US DOE Energy Efficiency and Renewable Energy, State Energy Alternatives
http://www.eere.energy.gov/states/alternatives/biomass.cfm

4. Electricity From: Biomass
http://powerscorecard.org/tech_detail.cfm?resource_id=1

V. Any uncertainty associated with the option: High.
VI. Level of agreement within the work group for this mitigation option: To Be Determined.
VII. Cross-over issues to the other Task Force work groups
Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

Mitigation Option: Bioenergy Center

I. Description of the mitigation option

Sunflower Electric Power Cooperative is planning a bio-energy center adjacent to their coal fired electric plant in rural Kansas[1].Three new 700 MW units are planned to supplement the existing 360 MW unit. The bioenergy center promises some CO2 mitigation along with energy efficient and low pollution auxiliary business enterprises. The bioenergy center concept involves a feedlot, dairy, anaerobic digester, algae reactor, ethanol plant, biodiesel plant, and the coal plant. Methane, electricity, ethanol, and biodiesel will be produced. The wastes (water, manure, biogas, nitrogen, phosphorus, flue gas, glycerol, CO2, wet distiller's grain, and ammonia) are used for inputs for the processes, rather than being discarded.

The anaerobic digester processes manure to produce methane to power the ethanol plant. The algae reactor consumes CO2 from the coal plant flue gas, and nitrogen and phosphorus from the anaerobic digester. The reactor then produces oil-rich protein for biodiesel production, with the residue used for livestock feed. The ethanol plant will consume corn and grain sorghum, and produce wet-distillers grain for livestock feed.

Locally, there could be variations on this theme. Excess corn fodder biomass, not fed to livestock, could be burned in the power plant. Only the grain is useful in ethanol production with current technology. Livestock could be omitted and the ethanol plant powered with natural gas.

Benefits: Any burned biomass has close to zero net effect on CO2 emissions from the coal fired power plant. Energy efficient businesses produce ethanol and biodiesel for sale. Local economic growth is enhanced, with increased national energy independence. Waste products are recycled that would otherwise have to be disposed.

Tradeoffs:
Land is needed to grow grain crops
Nitrate run-off from needed fertilizer
Ancillary energy usage, and lowering of CO2 net efficiency, to cultivate, harvest, and transport the crop, and remove waste products

II. Description of how to implement

A. Mandatory or voluntary: Voluntary.
It should be more feasible to plan such an adjunct facility at the proposed Desert Rock Power Plant, rather than at the existing power plants. Livestock and grain crops could be expanded at the NAPI, resulting in short transportation distances. Sithe Global is required to provide financing for local environmentally beneficial projects as an offset for tax benefits. This could help fund the feasibility studies for this project and a portion of the construction costs.

B. Indicate the most appropriate agency(ies) to implement
Navajo Nation, San Juan County, State of New Mexico economic development departments

III. Feasibility of the option

A. Technical – Co-firing biomass in coal plants is proven technology. Ethanol plants are being constructed at a rapid pace. There is a local construction company with extensive experience with ethanol plants. Each bio-energy component has been commercialized to some degree, but the challenge is the integration of these components in an energy center.

B. Environmental – VOC emission output from an ethanol plant could be mitigated by vapor capture routed to the power plant, or to a thermal oxidizer. The thermal oxidizer could accommodate vapors from the biodiesel plant. A portion of the power plant and thermal oxidizer CO_2 emissions would be mitigated by the algae reactor. Expanded feedlot activities have associated groundwater, ozone layer (methane), and odor impacts.

C. Economic – Detailed economic modeling is needed along with the engineering studies to provide input to a viable business plan. A renewable energy project should attract grant money and gain tax benefits. Labor infrastructure at the Desert Rock construction site could be leveraged to construct, then operate the bio-center.

IV. Background data and assumptions used

1. "Farming for Energy" Sunflower Electric's Bioenergy Center in Kansas – EnergyBiz Magazine, Jan./Feb. 2007 -- www.energycentral.com

2. Kansas Technology Enterprise Corporation -- http://www.ktec.com/index_Flash.htm

3. Four Corners Air Quality Task Force Mitigation Option "Biomass Power Generation"

V. Any uncertainty associated with the option (Low, Medium, High) High

VI. Level of agreement within the work group for this mitigation option To be discussed.

VII. Cross-over issues to the other Task Force work groups

Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

Mitigation Option: Nuclear Option

I. Description of the mitigation option

Nuclear reactor power generation should be considered as a mitigation option. We should not assume that it is too politically controversial for consideration. The mitigation options would lack balance if the taskforce were not to consider a future nuclear power plant. Such a plant would have virtually zero air emissions and global warming impact.

The U.S. Nuclear Regulatory Commission is adding staff to consider up to 30 nuclear units in fiscal 2008. This was motivated by the Energy Policy Act of 2005, which has invigorated the power industry to come forward with new plans. A new NRC office has been created solely for licensing and oversight of new reactor activities, with a current staff of 240. Many of these units will be in the south and southeast, where utilities have prior nuclear experience. NRC has streamlined their processes so standard design certifications will be approved, and the safety design hurdle will not be raised continually. Many of these applications will be active pump/valve cooling designs that meet the stringent safety requirements of standard design certifications.

These designs include the GE AWBR (Advanced Boiler Water Reactor), the Areva EPR (Evolutionary Power Reactor), and the Mitsubishi advanced pressurized water reactor. Bechtel is working on standard, pre-engineered modular designs, so that units can be replicated quickly and cost effectively. Construction time is approximately four to five years. If fifteen units were to be built from now until 2020, there would be a need for 30,000 new high-paying craft jobs. Several utilities are committing to these designs because of the certainty they will be completed on schedule with low risk financing, and their operating experience at similar plants.

There is promise for a family of passive cooling reactors, where gravity/density differences provide equivalent convection cooling protection to electrically powered valves and pumps. These designs would be simpler and less expensive than current active pump designs. Much design work has been done, although there is not currently such a unit in operation. General Electric is offering its ESBWR (Economically Simplified Boiling Water Reactor) and Westinghouse its AP1000, an advanced passive reactor. TVA and Entergy are considering use of this technology. Plants of this type will be among those soon licensed by the NRC.

Nuclear plants have lower maintenance costs (about 1.7 cents per kwh, v.s. 3 - 5 cents for a fossil fuel units). Operating experience has advanced greatly over the 30 years since Three Mile Island, with plants running at 90% capacity -- up from 70% in the 1970s.

Opposition will come from perceived plant safety and spent fuel issues. Regional storage of spent fuel already exists in New Mexico. It is likely that Yucca Mountain will be licensed for long term storage. New Mexico should participate in research for the safe long term storage of spent nuclear fuel. There is strong congressional and public recognition that nuclear power generation should be part of the energy portfolio, along with increased renewables, to address climate change. There is also a 20-30% group that opposes both existing and future nuclear power generation. This level of opposition would also be expected in New Mexico, and must be considered in any political process to license a nuclear plant locally. Worldwide, especially in China and India, there is a very active nuclear buildout in progress. Nuclear power generation is actively expanding worldwide, and about to in the United States.

A realistic approach would keep our options open politically, while closely monitoring the re-emergence of the nuclear industry in the United States over the next 5 – 10 years. We should especially follow the operating experience of the new passive cooling reactors which should be on-line in less than ten years.

New Mexico is already in an area of low seismic activity. The additional safety advantage of a passive reactor design should lower public opposition significantly. Much of the anticipated surge of nuclear construction is by existing utilities that already operate conventional nuclear plants. It makes economic sense for many of them to continue in this direction. That argument does not hold in New Mexico, and we should embrace the construction of one or more passive nuclear power reactors as this technology matures.

We would expand our use of local coal reserves with the new Desert Rock power plant, and enjoy very low air emissions from that plant, except for the increased carbon footprint. Longer term (10 – 20 years), as power needs increase, we should consider a passive reactor nuclear plant instead of another coal fired plant. Some existing local coal fired units may approach the end of their design life and be retired. That retired power could be replaced by nuclear generation, with zero air emissions and carbon footprint.

A nuclear building program in the Four Corners would greatly enhance the growth of a local and regional high technology professional and vocational workforce. San Juan College would step up with new programs to educate the vocational workforce needed to build and operate a nuclear plant. The college should also benefit from creative financing support similar to that proposed for Desert Rock. The Four Corners and New Mexico would be recognized as an energy focal point in the U.S., with an exceptional balance of conventional, renewable, and nuclear energy generation, along with our strong base in oil/gas production.

Benefits: Zero air emissions impact; No carbon footprint; Cost effective electricity generation; Foster high technology educational and employment basis in the Four Corners; Proximity to current New Mexico and future Nevada spent fuel storage site.

Tradeoffs: Minority negative public opinion related to plant safety and spent fuel containment.

Differing Opinion: While it may be true that nuclear power plants have almost no carbon dioxide emissions (except in construction and in mining, processing and supplying the uranium fuel) and low global warming impact, there are other enormous liabilities which make them, in my opinion, the least desirable alternative to replace fossil fuel-fired power plants.

The availability of fissionable uranium (U-235) is not discussed. The supply will be quite limited, especially if the rate of usage increases significantly. One proposed solution, going to breeder reactor technology, would involve transport of radioactive materials to and from reprocessing plants, entailing enormous problems of safety and security.

The stated maintenance cost of 1.7 cents per Kwh for nuclear plants is deceptive. In all likelihood it does not include the cost of decommissioning the facility at the end of its useful life, nor the totally unknown cost of eventual "permanent" storage of the radioactive waste products. It also does not include any portion of the massive and continuing federal subsidies for nuclear R&D ($145 billion between 1947 and 1998 according to one source).

The issue of permanent storage of radioactive wastes (spent fuel) is not adequately discussed. The federal government and the nuclear industry have had half a century to develop permanent storage facilities; it seems they are no closer to a solution than when they started. Yucca Mountain is not close to viable, the latest blow being a federal court decision upholding the Nevada State Water Engineer's authority to deny the federal government's use of groundwater at the site. Even if a permanent storage facility is eventually developed, there is a major moral issue. I do not believe we have the right to impose an almost perpetual guardianship role on future generations (8,000 generations if the estimate of a 200,000 year storage time for plutonium wastes is accurate).

II. Description of how to implement
A. Mandatory or voluntary
B. Indicate the most appropriate agency(ies) to implement

III. Feasibility of the option
A. Technical –
B. Environmental –
We would expand our use of local coal reserves with the new Desert Rock power plant, and enjoy very low air emissions from that plant, except for the increased carbon footprint. Longer term (10 – 20 years), as power needs increase, we should consider a passive reactor nuclear plant instead of another coal fired plant. Some existing local coal fired units may approach the end of their design life and be retired. That retired power could be replaced by nuclear generation, with zero air emissions and carbon footprint.
C. Economic –
Nuclear plants have lower maintenance costs (about 1.7 cents per kwh, v.s. 3 - 5 cents for a fossil fuel units). Operating experience has advanced greatly over the 30 years since Three Mile Island, with plants running at 90% capacity -- up from 70% in the 1970s.

IV. Background data and assumptions used:
Reference: Energybiz magazine Vol. 4, Issue 3 (May 07, June 07) "Agency Gets Ready for Nuclear Renaissance" -- "Repackaging the Nuclear Option" -- "GE Gears Up." Vol. 4, Issue 4 (July 07, August 07) “Bechtel sees Nuclear Surge” and “The Nuclear Balance Sheet.”

V. Any uncertainty associated with the option: TBD
VI. Level of agreement within the work group for this mitigation option: To Be Determined.
VII. Cross-over issues to the other Task Force work groups:
Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

OVERARCHING: POLICY

Mitigation Option: Reorganization of EPA Regions

I. Description of the mitigation option

The Four Corners geographic area is under the jurisdiction of three different regions of the Environmental Protection Agency: Colorado and Utah are in Region 8, headquartered in Denver; New Mexico is in Region 6, headquartered in Dallas; and Arizona (and the Navajo Nation, which is in both Arizona and New Mexico) is in Region 9, headquartered in San Francisco.

Due to the abundance of coal and oil and gas in the San Juan Basin energy development in the area is likely to continue. It is becoming increasingly well-documented that the majority of the pollution experienced in the Four Corners area is coming from coal-fired power plants on or near reservation lands in New Mexico as well as oil and gas development throughout the region. The EPA staff engaged in addressing environmental impacts from oil and gas development, and responsible for actually permitting or overseeing permitting of stationary sources (power plants) needs to be located where the pollution is happening and be responsible to the recipients of that pollution as well as to hold its generators accountable.

A permanent EPA human presence within the area of energy development and pollution would sensitize EPA personnel to the issues within the Four Corners area. Creating an interregional office of the EPA with jurisdictional authority in order to include within a single jurisdiction the pollution generating sources and the public lands and communities they impact would improve EPA effectiveness in oversight and permit processing by facilitating communication and focusing feedback.

II. Description of how to implement

Create a permanent inter-region office within the EPA chartered to focus on, and located in, the Four Corners region. The office would assume all regional duties with respect to the Four Corners area, and have responsibility for overseeing state and tribal permitting, permitting stationary sources in the absence of state or tribal permitting, and any activities relating to oil and gas development currently performed by the various regions.

III. Feasibility of the Option

EPA Headquarters, as well as the three regions involved, would need to approve this option. The states and tribes would need to support this option as well.

IV. Background data and assumptions

The statement by Colleen McKaughan of Region 9 to the Durango Herald epitomizes our perception of the sensitivity of Region 9 personnel to the issues in the Four Corners region. As quoted in the Durango Herald on September 15, 2006, Ms. McKaughan, an air-quality expert with the federal Environmental Protection Agency's Region 9, said the Four Corners region has air so clean that it can absorb additional pollutants without harm. She said the EPA had no significant concerns about the proposed coal-fired Desert Rock plant.

V. Any uncertainty associated with the option There is a high level of uncertainty in getting something like this passed politically and how long it would take is an unknown.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues Oil and Gas Work Group, Other Sources Work Group.

OVERARCHING: MERCURY

Mitigation Option: Clean Air Mercury Rule Implementations in Four Corners Area

I. <u>Description of the mitigation option</u>

States and tribes are presently drafting regulations (some such as NM and CO now have completed rules, see appendix on NM & CO) to meet the Clean Air Mercury Rule (CAMR) while simultaneously meeting their mission to protect public health and the environment. For states, this means allocating mercury allowances to electric generating facilities to operate. CAMR may eventually have profound effects on the amount of mercury reduced from the affected facilities.

States participating in the Task Force might work in concert to determine if even greater reductions are possible than initially scheduled in CAMR. Some examples of working in concert might include:

- "Incentivizing" early mercury reductions at CAMR-affected facilities;
- Retiring any excess allowances that may exist (Colorado has in effect a "Colorado Citizens' Trust" to effectively permanently set aside excess allowances);
- Addressing the concerns for local mercury impacts ("hot spots") from new and proposed facilities in the Four Corners area by requesting that State air quality permitting agencies consider this hot spot criterion in their decision to approve/disapprove facilities' air quality permit requests (as individual state budgets and their "set aside allowances" may be inappropriate indicators of the impacts the local area might receive from power plants in Four Corners);
- Promoting additional mercury studies (e.g., air deposition) that would benefit Four Corners area (could/should be tied to option #5);
- Requiring early installation of mercury CEMs at facilities (to better gauge effectiveness of various co-control efforts);
    - For example, Mercury CEMs will be installed on 2 of the 4 units at San Juan by 12/31/07 and the other 2 units by 12/31/08.
- Developing more stringent control requirements for facilities in Four Corners Area;
- Other examples as identified.

II. <u>Description of how to implement</u>

<u>A. Mandatory or voluntary:</u>

Could be either mandatory or voluntary depending on the specifics of the option.

Differing Opinion: Since many of Four Corners Area lakes, streams, and rivers are currently under a mercury advisory, mandatory control of mercury is necessary. The health of humans and other living beings is at risk

<u>B. Indicate the most appropriate agency(ies) to implement:</u>

States' environmental (permitting) agencies

<u>III. Feasibility of the option</u>

<u>A. Technical:</u> Some of the technical options may be difficult to implement, especially depending on the timing. That is, CAMR plans are due to EPA by November 2006 and hence options developed here may come too late. However, options developed here could be possibly used in the states' future allocation schemes and/ or approaches surrounding CAMR.

<u>B. Environmental:</u> N/A

<u>C. Economic:</u> Difficult to ascertain as this depends on the specifics of the option developed.

IV. Background data and assumptions used

CAMR information and data are plentiful; however, the long-term application and effectiveness of various strategies to reduce mercury from power plants is difficult to predict.

Basic Information on New Mexico CAMR:

- Rule applicability covers coal-fired EGUs (presently 4 units at San Juan Generating Station and 1 unit at Escalante Generating Station).
- Mandatory mercury monitoring by sources begins 1/1/09.
- Mercury limitations become effective 1/1/10.
- See Tables 1 and 2, below, for mercury emissions data and proposed limitations.
- Monitoring includes installing monitoring systems (CEMS or sorbent traps), certification, performance test, and recording, quality-assuring, and reporting data.
- Initial monitoring performance test is 12 months (calendar year 2009).
- State rules takes state "budget" and turns it into state "cap" with portions of the cap assigned to facilities as facility-wide emission limitations as well as EPA-recommended new source set-aside.
- State rules prohibit participation in trading and banking program.
- State rules establish emissions fees to support one full-time equivalent for implementation of the mercury rules.

Table 1: New Mexico Mercury Emissions Data	
New Mexico Mercury Emissions (1999 EPA data; Tons)	1.09
New Mexico Mercury Emissions (2004 TRI data; SJGS + Escalante; Tons)	0.389
New Mexico Mercury Budget (2010-2017; Tons per year)	0.299
New Mexico Mercury Budget (2018 and after; Tons per year)	0.118

Table 2: New Mexico Mercury Limitations (Per year)						
	2010-2017			**2018 and after**		
	Tons	Ounces	%	Tons	Ounces	%
Total "State Cap"	0.299	9,568	100 %	0.118	3,776	100 %
San Juan Generating Station	0.244	7,808	81.6 %	0.104	3,323	88 %
Escalante Generating Station	0.04	1,280	13.4 %	0.01	340	9 %
New Source Set-Aside	0.015	480	5 %	0.035	113	3 %

Basic Information on Colorado CAMR:

Overview: Colorado's Air Quality Control Commission adopted a rule specific to CO's Utility Hg Reduction Program on 2/6/07. This rule specifies 100% of the state's allowances be transferred into the State's General Account. The State allocates allowances to units based on annual actual emissions, up to Model Rule allocations with an option to access additional allowances based on need through a safety-valve. In addition, the rule requires phased reductions over time on a rolling 12-month average basis, exempting low mass emitters and new units with existing permits in place:

• 2012: Pawnee and Rawhide 0.0174 lb/GWh or 80% inlet Hg capture;
• 2014: 0.0174 lb/GWh or 80% inlet Hg capture; and
• 2018: 0.0087 lb/GWh or 90% inlet Hg capture.

This rule allows for averaging of units at the same plant. The rule also provides soft-landing, requiring Best Available Mercury Control Technology installation if units demonstrate to the State that they cannot meet the performance standard. Finally, the rule includes a provision associated with retirement of allowance accrual, beginning in 2016, 2019 and every five years thereafter, if no separate rulemaking is commenced prior.

Trading: Yes, but allocations are made based on actual emissions.

Allowance Allocations: Up to 95% in phase I and 97% in phase II, with the remainder used for new units. However, actual allocations are made based on actual emissions, which are reduced over time due to state-only Hg emission standards. Therefore allocation amounts are also expected to decrease over time.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium – again, the long term application and effectiveness of various strategies to reduce mercury from power plants is difficult to predict.

VI. Level of agreement within the work group for this mitigation option

TBD.

VII. Cross-over issues to the other Task Force work groups

TBD.

Mitigation Option: Federal Clean Air Mercury Rule (CAMR) Implementation on the Navajo Nation

I. Description of the mitigation option

The Environmental Protection Agency (EPA) promulgated the Clean Air Mercury Rule (CAMR) on May 18, 2005. CAMR established a mechanism by which mercury (Hg) emissions from new and existing coal-fired power plants (EGUs) are capped at nation-wide levels of 38 tons/year effective in 2010 and 15 tons/year effective in 2018. EPA then established Hg emission levels for each state and for Indian country in cases where there are existing EGUs; this includes the Navajo Nation. State and Tribal plans to implement and enforce Hg emission levels were to be submitted to EPA by November 17, 2006. State plans can be more stringent than the EPA Model Rule and may or may not allow trading or banking of emissions allowances.

In cases where a State or Indian Tribe does not have an approvable plan in place by the prescribed deadline of March 17, 2007, EPA may implement a Federal plan by May 17, 2007. In order to facilitate this action, EPA published proposed rules on December 22, 2006. These rules are expected to be finalized by May 17, 2007, and will be used to implement CAMR on the Navajo Nation. A major shortcoming of these EPA rules is the lack of provision for meaningful public participation in the process to develop and allocate specific Hg emission limits for existing and proposed EGUs on Navajo Nation lands. This is significant since the Navajo Nation mercury emissions budget is larger than that of either Arizona, New Mexico, or Utah, and almost as large as the budget for Colorado.

The Navajo EPA, Region 9 EPA, and the operating agencies for the Four Corners Power Plant and the Navajo Generating Station – Arizona Public Service Company (APS) and the Salt River Project Agricultural Improvement and Power District (SRP), respectively – have already had discussions regarding a potential allocation methodology for the Navajo Nation. A meeting was held on July 10, 2006, at which Region 9 EPA presented a "strawman" proposal which differed significantly from the EPA model Rule with respect to the amount and disposition of the new source set-aside portion. This proposal has not been well-received by APS and SRP. The degree to which the air quality agencies in the surrounding, contiguous, and sometimes overlapping States of Arizona, Colorado, New Mexico and Utah have been aware of these early meetings is not known. From all appearances it seems that much greater effort should go towards facilitating adequate public participation in this process. The prime responsibility for achieving this rests with Region 9 EPA.

At a minimum the process for allocation of mercury emissions limits to EGUs in Navajo lands should be at least as open to public participation as the most transparent State CAMR process has been. For the Navajo Nation this might include informational meetings and public hearings in Window Rock and Page, Arizona, and Farmington, New Mexico. Final decisions on nature and location of meetings should be negotiated among the various jurisdictional agencies.

II. Description of how to implement

A. Mandatory or voluntary

This should be mandatory. In the past, public participation has been a cornerstone of EPA policy and in fact is mandated in many of their regulations.

B. Indicate the most appropriate agencies to implement

Region 9 EPA, with assistance and cooperation of Navajo EPA and air quality agencies in affected States.

III. Feasibility of the option

A. Technical: Entirely feasible

B. Environmental: Feasible

Economic: Feasible; minor administrative costs to conduct public meetings and hearings
Political: Medium feasibility. Some advocacy to Region 9 EPA may be needed to implement this option.

IV. Background data and assumptions used

A small amount of information has been received from Region 9 EPA.
Clean Air Mercury Rule making process is in process so newer information may now be available

V. Any uncertainty associated with the option

Medium – responsibility to implement rests primarily with Region 9 EPA.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other Task Force work groups TBD

OVERARCHING: AIR DEPOSITION STUDIES

Mitigation Option: Participate in and Support Mercury Studies

I. Description of the mitigation option

Background

Rationale and Benefits: Methyl mercury is a known neurotoxin affecting humans and wildlife. Coal-fired power plants are the number one source of mercury emissions in the United States[1]. The Four Corners already is home to several power plants that are large emitters of mercury and additional coal-powered plants are proposed for the region. Individuals and community groups in the San Juan Mountains have expressed great concern about mercury emissions in our region and the existing mercury fish consumption advisories in several reservoirs. Studies of mercury in air deposition, the environment and in sensitive human populations (such as pregnant women) are necessary to set a baseline for current levels and to detect future impacts of increased mercury emissions on these sensitive human populations and natural resources, including the Weminuche Wilderness, a Federal Class I Area.

Existing mercury data for the Four Corners region: Total mercury in wet deposition has been monitored at Mesa Verde National Park since 2002 as part of the Mercury Deposition Network (MDN)[2]. Results show mercury concentrations among the highest in the nation. Mercury concentrations have been measured in snowpack at a few sites in the San Juan Mountains by the USGS[3] and moderate concentrations similar to the Colorado Front Range have been recorded. Mercury concentrations in sport fish from several reservoirs have exceeded the 0.5 microg/g action level resulting in mercury fish consumption advisories for McPhee, Narraguinnep, Navajo, Sanchez and Vallecito Reservoirs[4]. Sediment core analysis for Narraguinnep Reservoir show that mercury fluxes increased by approximately a factor of two after about 1970[5]. Finally, atmospheric deposition just to the surface of McPhee and Narraguinnep Reservoirs (i.e., not including air deposition to the rest of the watershed) is estimated to contribute 8.2% and 47.1% of total mercury load to these waterbodies, respectively[6].

Data Gaps: Very little data exists for the Four Corners Region with which to assess current risks and trends over time for mercury in air deposition, ecosystems, and sensitive human populations. Mercury amounts and concentrations in wet deposition at Mesa Verde National Park are not likely to portray the situation in the mountains where mercury may be deposited at higher concentrations and total amounts because of greater rates of precipitation and the process of cold condensation, which causes volatile compounds to migrate towards colder areas at high elevation and latitude[7]. No information about total mercury deposition from the atmosphere (i.e., including dry deposition) exists for low or high elevations in the Four Corners Region. Furthermore, analysis of sources of air deposition of mercury is lacking. Except for a handful of reservoirs, no information exists for incorporation of mercury into aquatic ecosystems and subsequent effects on food-webs. No systematic effort exists to document mercury impacts in a wide range of waterbodies over space and time. Lastly, impacts of mercury exposure to human populations are unknown.

Three new studies have begun or will begin in 2007, however. In 2007, the Mountain Studies Institute (MSI) will measure total mercury in bulk atmospheric deposition (collector near NADP station at Molas Pass), in lake zooplankton (invertebrates eaten by fish), and in lake sediment cores in the San Juan Mountains, a project funded by the U.S. EPA and USFS[8]. Dr. Richard Grossman is measuring mercury levels in hair collected from pregnant women in the Durango vicinity. Lastly, the Pine River Watershed Group (via the San Juan RC&D) recently was granted start-up funds to initiate event-based sampling of mercury in atmospheric deposition at Vallecito Reservoir and accompanying back-trajectory analyses to locate the source of these storm events.

Option 1: Install and operate a long-term monitoring station for mercury in wet deposition for a location at high elevation where precipitation amounts are greater than the site at Mesa Verde NP. Co-location of the collector with the NADP site at Molas Pass would provide data pertinent to Weminuche Wilderness and the headwaters of Vallecito Reservoir. This monitor would be part of the Mercury Deposition Network (MDN). Upgrading the NADP monitoring equipment at Molas Pass to include the MDN specifications would cost $5,000 to $6,000, while annual monitoring costs are $12,112 plus personnel as of September 2006.

Option 2: Install and operate a long-term monitoring station for mercury in total deposition (wet and dry) for at least one MDN station in the Four Corners Region. Speciated data will be collected and analyzed as is feasible. The MDN is currently developing this program and costs are anticipated at about $50,000 per year.

Option 3: Support multi-year comprehensive mercury source apportionment study to investigate the impact of local and regional coal combustion sources on atmospheric mercury deposition. This type of study would require additional deposition monitoring (i.e., recommendations 1 & 2 above). Speciated data will be collected and analyzed as is feasible. A mercury monitoring and source apportionment study was recently completed for eastern Ohio. (http://pubs.acs.org/cgibin/asap.cgi/esthag/asap/html/es060377q.html[9]). This study would build on the pilot study planned for Vallecito Reservoir. Costs TBD.

Option 4: Support a study of mercury incorporation and cycling in aquatic ecosystem food-webs, including total and methyl mercury in the food-webs of lakes and wetlands. This option includes studies that determine which ecosystems currently have high levels of total and methyl mercury in food-web components, how mercury levels in ecosystems change over time, where the mercury is coming from, and what conditions are causing the mercury to become methylated (the toxic form of mercury that bio-accumulates in food-webs). This information would allow tracking of mercury risks over time and space and serves as the basis for predicting future impacts. Existing reservoir studies and the upcoming MSI investigation serve as a starting point to build a collaborative and systematic approach. Costs TBD.

Option 5: Support continued studies of mercury concentrations in sensitive human populations in the region to understand what exposure factors increase likelihood of unhealthy mercury levels in the body. Dr. Richard Grossman's study serves as a starting point to continue this effort. Costs TBD.

Option 6: Form a multi-partner Mercury Advisory Committee that would work collaboratively to prioritize research and monitoring needs, develop funding mechanisms to sustain long-term mercury studies, and work to communicate study findings to decision-makers. The Committee would include technical experts and stakeholder representatives from States, local governments, land management agencies, watershed groups, the energy industry, etc.

II. Description of how to implement

See above. Studies would utilize the existing Mercury Deposition Network and expertise developed from past and ongoing studies. Investigators could include scientists from academia, non-profit, private and government organizations and agencies.

III. Feasibility of the Option

Technical -Very feasible; all technology exists or is in development for the above options.

Environmental – Very feasible. Harmful effects on the environment are negligible and permits for sample collection should be easy to obtain.

Financial – Uncertain. It is likely that a consortium of funding entities collaborate for these options. Potential partners include States, industry, US-EPA, USDA-Forest Service, US-Department of Energy, and local governments, watershed groups and public health organizations.

IV. Background data and assumptions used See introduction section

V. Any uncertainty associated with the option Funding uncertainty.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups Energy and Monitoring Groups

Citations:

[1] See http://www.epa.gov/mercury/about.htm.
[2] National Atmospheric Deposition Program (NADP). Mercury Deposition Network http://nadp.sws.uiuc.edu/mdn/. National Trends Network. http://nadp.sws.uiuc.edu/.
[3] Campbell, D, G Ingersoll, A Mast and 7 Others. Atmospheric deposition and fate of mercury in high-altitude watersheds in western North America. Presentation at the Western Mercury Workshop. Denver, CO. April 21, 2003.
[4] Colorado Department of Public Health and Environment website: http://www.cdphe.state.co.us/wq/FishCon/FishCon.htm and http://www.cdphe.state.co.us/wq/monitoring/monitoring.html.
[5] Gray, JE, DL Fey, CW Holmes, BK Lasorsa. 2005. Historical deposition and fluxes of mercury in Narraquinnep Reservoir, southwestern Colorado, USA. Applied Geochemistry 20: 207-220.
[6] Colorado Department of Public Health (CDPHE). 2003. Total Maximum Daily Load for Mercury in McPhee and Narraguinnep Reservoirs, Colorado: Phase I. Water Quality Control Division. Denver, CO. http://www.epa.gov/waters/tmdldocs/Mcphee-NarraguinnepTMDLfinaldec.pdf.
[7] Schindler, D. 1999. From acid rain to toxic snow. Ambio 28: 350-355
[8] See http://www.mountainstudies.org/Research/airQuality.htm.
[9] See http://pubs.acs.org/cgi-bin/asap.cgi/esthag/asap/html/es060377q.html

OVERARCHING: GREENHOUSE GAS MITIGATION

Mitigation Option: CO_2 Capture and Storage Plan Development by Four Corners Area Power Plants

I. Description of the mitigation option
Carbon sequestration refers to the provision of long-term storage of carbon in the terrestrial biosphere, underground, or the oceans so that the buildup of carbon dioxide (the principal greenhouse gas) concentration in the atmosphere will reduce or slow. In some cases, this is accomplished by maintaining or enhancing natural processes; in other cases, novel techniques are developed to dispose of carbon.

Emissions of CO_2 from human activity have increased from an insignificant level two centuries ago to over twenty five billion tons worldwide today (1). The additional CO_2, a major contributor to Greenhouse gases, contribute to the phenomenon of global warming and could cause unwelcome shifts in regional climates (1).

The contribution of CO_2 from the 2 major power plants in the 4Corners area is approximately 29,000,000 Tons of CO_2 per year. The proposed Desert Rock Energy Project would add an approximate additional 11,000,000 Tons of CO_2 per year.

Facilities in the Four Corners area should begin developing carbon sequestration plans to mitigate this important global issue. Four Corners area power plants should research & develop way to reduce their CO_2 emissions.

Benefits: CO_2 emissions reductions would reduce the Greenhouse Gases output of the 4Corners area. Carbon sequestration would slow the buildup of CO_2 emissions in the atmosphere. It would be a regional action to reducing the trends of global warming. Benefits would be environmental and economic. CO_2 capture and injection may have a beneficial use for enhanced oil recovery in the 4C area

Tradeoffs: no tradeoffs

Burdens:
The benefits of protecting the climate will be realized globally and far in the future; the cost of each GHG emissions reduction project is local and immediate.

Cost to power plants, administrative costs.

Sequestration, isolating the CO_2 emissions is cheap; however, capturing/storing is expensive.

II. Description of how to implement
A. Mandatory or voluntary
Combination of mandatory and voluntary
Voluntary: 4C area power plants should begin developing Carbon Sequestration Plans
Mandatory limits or allocations may be set by State and Federal regulators in the near future.

B. Indicate the most appropriate agency(ies) to implement
State and Federal Regulators can allocate Carbon budgets which will lead to more controls
Appropriate State/Federal agencies to help assess Carbon potential storage areas as part of planning process

III. Feasibility of the option

A. Technical: Technologies exist; many are in R&D phase.
B. Environmental: Capturing and storing CO_2 emissions is difficult.
C. Economic: Capturing CO_2 emissions is expensive.
D. Legal: Liability of CO_2 storage process

IV. Background data and assumptions used

1. Carbon Sequestration Technology Roadmap and Program Plan 2006, US DOE
2. CO2 emissions from Four Corners area power plants (4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10)
3. San Juan Generating Station has a total 1798 MW generation capacity, and emits approximately 13,097,000 Tons CO_2/yr. Approx 7,300 Tons CO_2 per MW generation capacity. San Juan Generating Station CO_2 rationing by MW is used as an estimation for CO_2 emissions from Desert Rock Energy Facility. Based on this assumption, the CO_2 emissions from Desert Rock Energy Facility will be approximately 11,000,000 Tons/yr.
4. US DOE Carbon Sequestration Regional Partnerships:
http://www.fossil.energy.gov/programs/sequestration/index.html
New Mexico Partnerships
http://www.fossil.energy.gov/programs/projectdatabase/stateprofiles/2004/New_Mexico.html

V. Any uncertainty associated with the option

Medium.

VI. Level of agreement within the work group for this mitigation option.

To Be Determined.

VII. Cross-over issues to the other Task Force work groups

CO_2 emissions reduction Cross-over issue with other energy industries such as Oil & Gas. Oil & Gas industries could also be held responsible for developing Carbon sequestration plans.

CO_2 capture and injection may have a beneficial use for enhanced oil recovery in the Four Corners area.

Mitigation Option: Climate Change Advisory Group (CCAG) Energy Supply Technical Work Group Policy Option Implementation in Four Corners Area

I. Description of the mitigation option

The New Mexico Climate Change Advisory Group (CCAG) is a diverse group of stakeholders from across New Mexico. At the end of 2006, the group will put forth policy options for reducing greenhouse gas emissions in NM to 2000 levels by the year 2012, 10% below 2000 levels by 2020 and 75% below 2000 levels by 2050. 69 recommendations covering transportation, land use, energy supply, agriculture and forestry were made which if implemented would exceed emissions reduction target for 2020.

A GHG emissions inventory for New Mexico prepared by The Center for Climate Strategies (2) showed electricity generation to comprise 40% of the states GHG emissions. The electricity generation sector is a source contributor of GHG and there are many areas for potential reductions. In the future, if the proposed Desert Rock Energy Project comes online, the additional 11 million tons of CO2 from Desert Rock would increase the electricity generation portion of New Mexico GHG emissions to approximately 50%.

The energy supply technical work group drafted options for renewable portfolio standards and advanced coal technologies (1). These policy options should be applied to Four Corners area facilities. The contribution of CO_2 from the 2 major power plants in the 4Corners area is approximately 29,000,000 Tons of CO_2 per year. The proposed Desert Rock Energy Project would add an additional estimated 11,000,000 Tons of CO_2 per year (3).

Local State/Federal Regulating agencies should work with the existing and proposed power plants to collaborate to help realize the targets of the Climate Change Advisory Group. CO_2 sequestration technologies and other Greenhouse gas mitigation strategies should be assessed and implemented to meet the targets.

Benefits:
Environmental: reduction of greenhouse gas emissions to 2000 levels by the year 2012, 10% below 2000 levels by 2020 and 75% below 2000 levels by 2050. Mitigation of adverse climate change effects

Net economic savings for the state's economy

Tradeoffs: none
Burdens: Cost to existing and proposed power pants and administrators

II. Description of how to implement

A. Mandatory or voluntary
Combination of mandatory and voluntary

B. Indicate the most appropriate agency(ies) to implement
State and Federal Regulators:
Oil Conservation Division (NMOCD)
New Mexico Air Quality Bureau
New Mexico Energy, Minerals, and Natural Resources Division

Other Four Corner State Environmental Protection Agencies

III. Feasibility of the option

A. Technical: TBD

B. Environmental: TBD
C. Economic: TBD

IV. Background data and assumptions used
(1) New Mexico Climate Change Advisory Group (CCAG): http://www.nmclimatechange.us/
(2) Draft New Mexico Greenhouse Gas Inventory and Reference Case Projections, The Center for Climate Strategies, July 2005
(3) CO_2 emissions from Four Corners area power plants (4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV9)
(4) San Juan Generating Station has a total 1798 MW generation capacity, and emits approximately 13,097,000 Tons CO_2/yr. Approx 7,300 Tons CO_2 per MW generation capacity. San Juan Generating Station CO_2 rationing by MW is used as an estimation for CO_2 emissions from Desert Rock Energy Facility. Based on this assumption, the CO_2 emissions from Desert Rock Energy Facility will be approximately 11,000,000 Tons/yr.
(5) Carbon Sequestration Technology Roadmap and Program Plan 2006, US DOE

V. Any uncertainty associated with the option Medium.

VI. Level of agreement within the work group for this mitigation option
To Be Determined.

VII. Cross-over issues to the other Task Force work groups
Greenhouse Gas (GHG) emissions reduction Cross-over issue with other energy industries such as Oil & Gas.

OVERARCHING: CAP AND TRADE

Mitigation Option: Declining Cap and Trade Program for NO_x Emissions for Existing and Proposed Power Plants

I. Description of the mitigation option

Cap and trade is a policy approach to controlling large amounts of emissions from a group of sources at costs that are lower than if sources were regulated individually. The approach first sets an overall cap, or maximum amount of emissions per compliance period, that will achieve the desired environmental effects. Authorizations to emit in the form of emission allowances are then allocated to affected sources, and the total number of allowances cannot exceed the cap.

Individual control requirements are not specified for sources. The only requirements are that sources completely and accurately measure and report all emissions and then turn in the same number of allowances as emissions at the end of the compliance period.

For example, in the Acid Rain Program, sulfur dioxide (SO_2) emissions were 17.5 million tons in 1980 from electric utilities in the U.S. Beginning in 1995, annual caps were set that decline to a level of 8.95 million allowances by the year 2010 (one allowance permits a source to emit one ton of SO_2). At the end of each year, EPA reduces the allowances held by each source by the amount of that source's emissions (1, EPA Clean Air Markets).

A declining cap and trade program means that the cap would be slightly lowered over time to reduce the total NOx emissions in the Four Corners area. A declining cap and trade program would be effective for the Four Corner areas' electric generating units.

The power plants in the area have continuous emissions monitors. We can measure accurately each plant's NOx emissions. In 2005 the NO_x emissions from San Juan Generating Station were 27,000 tons. The Four Corners Power Plant emitted 42,000 tons (2). Desert Rock Energy facility would add an approximate 3,500 tons/yr (2). NO_x emissions from electricity generating units (EGUs) will continue to be reported and recorded under the EPA Acid Rain Program (3). So the data is available. For each of these facilities the costs for additional controls and NO_x emissions reductions is different.

Electric Generating Units (EGUs) will be defined as it is EPA's Clean Air Interstate Rule:

(a) Except as provided in paragraph (b) of this definition, a stationary, fossil-fuel-fired boiler or stationary, fossil fuel fired combustion turbine serving at any time, since the start-up of a unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(b) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (a) of this definition starting on the day on which the unit first no longer qualifies as a cogeneration unit.

The program will cover all EGUs.

The Four Corners area declining cap and trade program would cap NO_x levels from EGUs at current levels. The cap could be lowered 5% every 10 years or a collaboratively agreed on level.

The Declining cap and trade program would include all EGUs in the Four Corners area, and could also possible be extended to oil & gas sources. New sources could obtain offsets.

There should be some discussion regarding how the cap would be set; as well as how to protect against hot spots.

Benefits: The cap will prevent NO_x emissions from the Four Corners area sources from increasing. Regardless of new power plants, sources will have to find a way to keep overall NO_x emissions below the declining cap.

The program will reduce NO_x emissions in the Four Corners area.
Power Plants would continue to look at new ways to reduce emissions.

Differing Opinion: Cap and trade is a band aid approach to reduction of emissions. It may look good on paper, but does nothing to enhance the air quality. Cap and trade should not be an option for power plant or oil and gas emissions in the Four Corners Area. Extensive improvement of the air quality and consideration for the health and welfare of the people and the environment should be the top priority.

Tradeoffs: None

Differing Opinion: The trade off of cap and trade is that the numbers look good, but in reality, the emissions are still in existence.

Burdens:
Regulatory agency needs to be able to collect, verify all emissions information and be able to enforce rule

II. Description of how to implement

A. Mandatory or voluntary
Mandatory

B. Indicate the most appropriate agency(ies) to implement
State Air Quality Agencies and Federal EPA

III. Feasibility of the option

A. Technical: NO_x emissions are measured using CEMS by large Power Plants. Complete and verified emissions measurements are reported by the Four Corners area power plants and is available on the EPA Clean Air Markets: Data and Maps National Database: http://cfpub.epa.gov/gdm/

B. Environmental: NO_x control technologies are available.
C. Economic: The design and operation of the program are relatively simple which helps keep compliance and administrative costs low. Cost savings are significant because regulators do not impose specific reductions on each source. Instead, individual sources choose whether and how to reduce emissions or purchase allowances. Regulators do not need to review or need to approve sources' decisions, allowing them to tailor and adjust their compliance strategies to their particular economics (1). Power Plants may need retrofits or to buy or sell credits.

* Cumulative Effects Work Group: How would a 5% declining cap and trade program for NO_x in the Four Corners area affect visibility and ozone levels?

IV. Background data and assumptions used

1. EPA Clean Air Markets – Air Allowances
http://www.epa.gov/AIRMARKET/trading/basics/index.html

A cap and trade program also is being used to control SO_2 and nitrogen oxides (NO_x) in the Los Angeles, California area. The Regional Clean Air Incentives Market (RECLAIM) program began in 1994. [1]

2. NO_2 emissions from Four Corners area power plants
(4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV9)
*NO_x emissions from existing power plants obtained from EPA Acid Rain database
*NO_x emissions from proposed Desert Rock Energy Facility from AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)

3. EPA Clean Air Markets: Data and Maps National Database: http://cfpub.epa.gov/gdm/

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option To Be Determined.

VII. Cross-over issues to the other Task Force work groups
Declining Cap and Trade program would cross-over with Oil & Gas work group.

Mitigation Option: Four Corners States to join the Clean Air Interstate Rule (CAIR) Program

I. Description of the mitigation option

EPA finalized the Clean Air Interstate Rule (CAIR) on March 10, 2005. It is expected that this rule will result in the deepest cuts in sulfur dioxide (SO_2) and nitrogen oxides (NOx) in more that a decade (1).

The Clean Air Interstate Rule establishes a cap-and-trade system for SO_2 and NO_x based on EPA's proven Acid Rain Program. The Acid Rain Program has produced remarkable and demonstrable results, reducing SO_2 emissions faster and cheaper than anticipated, and resulting in wide-ranging environmental improvements. EPA already allocated emission "allowances" for SO2 to sources subject to the Acid Rain Program. These allowances will be used in the CAIR model SO2 trading program. For the model NOx trading programs, EPA will provide emission "allowances" for NOx to each state, according to the state budget. The states will allocate those allowances to sources (or other entities), which can trade them. As a result, sources are able to choose from many compliance alternatives, including: installing pollution control equipment; switching fuels; or buying excess allowances from other sources that have reduced their emissions. Because each source must hold sufficient allowances to cover its emissions each year, the limited number of allowances available ensures required reductions are achieved. The mandatory emission caps, stringent emissions monitoring and reporting requirements with significant automatic penalties for noncompliance, ensure that human health and environmental goals are achieved and sustained. The flexibility of allowance trading creates financial incentives for electricity generators to look for new and low-cost ways to reduce emissions and improve the effectiveness of pollution control equipment (1).

While most of the states are in the Eastern half of the US, Texas is participating in the CAIR program. Four Corners states could also participate and realize the emissions reduction benefits of CAIR.

SO_2 and NO_x contribute to the formation of fine particles and NO_x contributes to the formation of ground-level ozone. Fine particles and ozone are associated with thousands of premature deaths and illnesses each year. Additionally, these pollutants reduce visibility and damage sensitive ecosystems (1).

By the year 2015, the Clean Air Interstate Rule will result in (Eastern US benefits) (1):
-- $85 to $100 billion in annual health benefits, annually preventing 17,000 premature deaths, millions of lost work and school days, and tens of thousands of non-fatal heart attacks and hospital admissions.
-- nearly $2 billion in annual visibility benefits in southeastern national parks, such as Great Smoky and Shenandoah.
-- significant regional reductions in sulfur and nitrogen deposition, reducing the number of acidic lakes and streams in the eastern U.S.

Based on an assessment of the emissions contributing to interstate transport of air pollution and available control measures, EPA has determined that achieving required reductions in the identified states by controlling emissions from power plants is highly cost effective (1).

States must achieve the required emission reductions using one of two compliance options: 1) meet the state's emission budget by requiring power plants to participate in an EPA-administered interstate cap and trade system that caps emissions in two stages, or 2) meet an individual state emissions budget through measures of the state's choosing (1).

CAIR provides a Federal framework requiring states to reduce emissions of SO_2 and NO_x. EPA anticipates that states will achieve this primarily by reducing emissions from the power generation sector.

These reductions will be substantial and cost-effective, so in many areas, the reductions are large enough to meet the air quality standards.

The Clean Air Act requires that states meet the new national, health-based air quality standards for ozone and PM2.5 standards by requiring reductions from many types of sources. Some areas may need to take additional local actions. CAIR reductions will lessen the need for additional local controls (1).

This final rule provides cleaner air while allowing for continued economic growth. By enabling states to address air pollutants from power plants in a cost effective fashion, this rule will protect public health and the environment without interfering with the steady flow of affordable energy for American consumers and businesses.

CAIR Timeline:
Promulgate CAIR Rule 2005, State implementation Plans Due 2006, Phase I Cap in Place for NOX, Phase I Cap in Place for SO2, Phase II Cap in Place for NOx and SO_2 (1). Caps will be fully met in 2015 to 2020, depending on banking.

The Four Corners area has existing and proposed power plants with significant NO_x and SO_2 emissions. The problem occurs over a relatively large area, there are a significant number of sources responsible for the problem, the cost of controls varies from source to source, and emissions can be consistently and accurately measured. Cap and Trade programs typically work better over broader areas. The Four Corners area as well as each state would realize a more successful Cap and Trade program from being a part of a large interstate program such as CAIR.

By joining the EPA CAIR program, the 4 Corner states of New Mexico, Colorado, Arizona, and Utah will also benefit from the interstate SO_2 and NOx emissions reductions.

Need some discussion on how to set cap, and protect against hot spots.

Benefits:
"If states choose to meet their emissions reductions requirements by controlling power plant emissions through an interstate cap and trade program, EPA's modeling shows that (for eastern states):

- In 2010, CAIR will reduce SO_2 emissions by 4.3 million tons -- 45% lower than 2003 levels, across states covered by the rule. By 2015, CAIR will reduce SO2 emissions by 5.4 million tons, or 57%, from 2003 levels in these states. At full implementation, CAIR will reduce power plant SO_2 emissions in affected states to just 2.5 million tons, 73% below 2003 emissions levels.
- CAIR also will achieve significant NOx reductions across states covered by the rule. In 2009, CAIR will reduce NOx emissions by 1.7 million tons or 53% from 2003 levels. In 2015, CAIR will reduce power plant NOx emissions by 2 million tons, achieving a regional emissions level of 1.3 million tons, a 61% reduction from 2003 levels. In 1990, national SO_2 emissions from power plants were 15.7 million tons compared to 3.5 million tons that will be achieved with CAIR. In 1990, national NO_x emissions from power plants were 6.7 million tons, compared to 2.2 million tons that will be achieved with CAIR (1)."

Tradeoffs: None
Burdens: Administrative costs on regulating agencies, including how to determine state or regional level cap; emissions control upgrade costs or purchasing allowances to power plants

II. Description of how to implement
A. Mandatory or voluntary

Mandatory emission caps, stringent emissions monitoring and reporting requirements with significant automatic penalties for noncompliance, ensure that human health and environmental goals are achieved and sustained (1).

B. Indicate the most appropriate agency(ies) to implement
State Air Quality Agencies and Federal EPA

III. Feasibility of the option

A. Technical: NOx emissions are measured using CEMS by large Power Plants. Complete and consistent emissions measurement and reporting by all sources guarantees that total emissions do not exceed the cap and that individual sources' emissions are no higher than their allowances

B. Environmental: NO_x, SO_2 control technologies are available.

C. Economic: The design and operation of the program are relatively simple which helps keep compliance and administrative costs low (2).

Cost savings are significant because EPA does not impose specific reductions on each source. Instead, individual sources choose whether and how to reduce emissions or purchase allowances. EPA does not review or need to approve sources' decisions, allowing them to tailor and adjust their compliance strategies to their particular economics (2).

The flexibility of allowance trading creates financial incentives for electricity generators to look for new and low-cost ways to reduce emissions and improve the effectiveness of pollution control equipment (1).

IV. Background data and assumptions used

1. EPA Clean Air Interstate Rule: http://www.epa.gov/cair/
2. EPA Clean Air Markets – Air Allowances
http://www.epa.gov/AIRMARKET/trading/basics/index.html
3. "EPA Enacts Long-Awaited Rule To Improve Air Quality, Health" Rick Weiss, Washington Post, Friday, March 11, 2005; Page A01 http://www.washingtonpost.com/wp-dyn/articles/A23554-2005Mar10.html
4. The White House – Council on Environmental Quality, Cleaner Air,
http://www.whitehouse.gov/ceq/clean-air.html

V. Any uncertainty associated with the option

Low – Program is based on a proven cap and trade approach
Need mechanism to be assured that a significant portion of actual reductions are achieved in the Four Corners area to assure the environmental benefit.

VI. Level of agreement within the work group for this mitigation option

To Be Determined

VII. Cross-over issues to the other Task Force work groups

Clean Air Interstate Rule would cross-over with Oil & Gas work group

OVERARCHING: ASTHMA STUDIES

Mitigation Option: Chronic Respiratory Disease Study for the Four Corners area to determine relationship between Air Pollutants from Power Plants and Respiratory Health Effects

I. Description of the mitigation option

This option would involve conducting a chronic respiratory disease study for the Four Corners area to determine the relationship between air pollutants from power plants and respiratory health effects. On going studies are necessary to continue to evaluate health risks associated with the large number of combustion emission sources in the area, primarily the two large coal-fired power plants in the area. Cumulatively, the two largest power plants in the area emit approx 66,000 tons/yr of nitrogen oxides (1). Nitrogen oxides are key precursor emissions to ozone.

Background

The NM Department of Health conducted a pilot project that linked daily maximum 8-hour ozone levels with the number of asthma-related emergency room visits at San Juan Regional Medical Center located in northwestern NM. The ozone and ER asthma data were collected for the period of 2000 - 2003. The number of emergency room visits in the summer increased 17% for every 10 ppb increase in ozone levels. This relationship occurred particularly following a two day lag and was statistically significant. These results are in general agreement with studies in other states and provide a foundation for tracking asthma-ozone relationships over time and space in NM (2).

The New Mexico Environment Department Air Quality Bureau operates and maintains three continuous ozone monitors in San Juan County. The eight-hour ozone design value in San Juan County has been maintained below the National Ambient Air Quality Standard for ozone of 0.08 ppm. The final eight-hour ozone design value for 2005 for San Juan County (San Juan Substation and Bloomfield monitors) was 0.072 ppm. The 2006 eight-hour ozone design value for San Juan County Substation monitor was 0.071 ppm. The 2006 eight-hour ozone design value for the San Juan County Bloomfield monitor was 0.069 ppm.

The Colorado Department of Public Health and Environment (CDPHE) has also researched asthma and links to environmental conditions. In a recent paper, “Holistic Approaches for Reducing Environmental Impacts on Asthma”, CDPHE, discusses staff researcher’s efforts to bring clarity to any identifiable linkage between environmental conditions and asthma. CDPHE investigated asthma rates throughout the state and compared these data against known and anecdotally reported information. Findings indicate that regions of Colorado do appear to have a higher incidence of asthma rates. In addition, some of the identified regions were not previously anticipated (e.g., rural communities), highlighting the need for further investigations (4).

The study describes asthma as a serious, chronic condition that affects over 15 million people in the United States. Asthma is a disease characterized by lung inflammation and hypersensitivity to certain environmental “triggers” such as pollen, dust, humidity, temperature and various environmental pollutants (dust, ozone, etc.), among others. Colorado has a particular problem with the occurrence of this condition, but the reasons for this are not well understood. Statewide there are an estimated 283,000 people with asthma, a figure that well exceeds national expectations. (4).

The CO-benefits risk assessment (COBRA) model is a recently developed screening tool that provides preliminary estimates of the impact of air pollution emission changes on ambient particulate matter (PM) air pollution concentrations, translates this into health effect impacts, and then monetizes these impacts

(5). A model such as this could be expanded to include other forms of air pollution such as ozone and be customized for the Four Corners Area.

Overarching modeling results should be cross-checked with local hospital inventory results and compared with other locations in the United States.

Benefits: Study would allow Four Corner area planning agencies to make better decisions and give the public a better idea of risk assessments

Tradeoffs: None

Burdens: Resources needed to conduct study

II. Description of how to implement

A. Mandatory or voluntary
Conduct coordinated outreach to obtain grant funding for the study.
(Study to be conducted by the end of 2009, with model development for assessing situation annually)

B. Indicate the most appropriate agency(ies) to implement
The states, the Environmental Protection Agency (EPA), and American Lung Association collaboration.

The need for these studies is obvious and the cost should be passed on to the utilities (and therefore the customers). However, even if these new studies find a significantly negative relationship between chronic respiratory disease and air pollutants, we already have proof that air pollutants increase the incidence of asthma. This mitigation option should include plans to utilize the study results for actively engaging policy-makers and changing regulations and enforcement, especially in geographic hot spots.

III. Feasibility of the option (indicate if assistance is needed from Cumulative Effects and/or Monitoring work groups)

Technical: The state and federal health organizations should be able to develop a 4C area model to assess the relationship between air pollutants from power plants and respiratory health effects

Environmental: Need for further modeling of Four Corners area customized to assessing respiratory health effect relationship to air pollutants from power plants. Existing COBRA model may be used as a starting point.

Economic: Grant funding would be required

*Monitoring work group: Assess whether or not we have the adequate data from monitoring stations to assess asthma situation. VOC and NOx emissions are contributors to ozone. Do we have good VOC data in the 4C area?

*Cumulative Effects work group: Assess the ozone trends in the 4C area. On average are ozone levels increasing or decreasing? Where are locations in the Four Corners area with the highest ozone concentrations? What are the relative contributions from power plants compared to oil and gas & other sources?

IV. Background data and assumptions used

(1) EPA Clean Air Markets – Data and Maps Query (2004 2005 2006 Facility & Unit Emissions Reports)
(2) New Mexico Department of Health Ozone Study
(3) New Mexico Environment Department – Ambient Ozone Level Data

(4) Holistic Approaches for Reducing Environmental Impacts on Asthma, Paper # 362, Prepared by Mark J. McMillan, Mark Egbert, and Arthur McFarlane, Colorado Department of Public Health and Environment.
(5) User's Manual for the CO-Benefits Risk Assessment (COBRA) Screening Model, US EPA, June 2006

V. Any uncertainty associated with the option Medium

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups Oil and Gas and Other Sources Work Groups

OVERARCHING: CROSSOVER

Mitigation Option: Install Electric Compression

I. Description of the mitigation option

Overview

- Electric Compression would involve the replacement or retrofit of existing internal combustion engines or proposed new engines with electric motors. The electric motors would be designed to deliver equal horsepower to that of internal combustion engines. However, the limitation of doing so is predicated by the electrical grid that would exist in a given area to provide the necessary capacity to support electrical compression.

According to projections, at least 12,500 new gas wells will be drilled in the San Juan Basin over the next 20 years. It is said that this gas field is loosing pressure and compression on thousands of wells is necessary. Pollution emissions from production engines are rapidly increasing. To date, there is no cumulative emissions measurement.
Using BLM figures, an average gas powered wellhead compressor at 353,685 hp-hr per year at 13.15g per hp-hr = 4,650,957 g/year of NO_x. This is just an example of NO_x emissions. This figure does not account for other compounds in exhaust emissions such as VOCs, carbon monoxide, etc. This is equivalent to a 17 car motorcade running non-stop, circling your house 24 hours per day.

Gas powered wellhead compressors and pumpjacks are being installed in close proximity to inhabited homes and institutions. The City of Aztec required electric compressors, although that ordinance was not enforced, on wellhead engines within the city limits prior to 2004 when the ordinance was revised. Electric engines were required in order to protect citizens from noxious emissions from gas fired engines near homes. Electric engines are thought to be quieter than gas fired engines; therefore reducing noise pollution also.

Gas fired engines are being installed on wells in close proximity to existing electric lines. Electric engines should be required on all sites near power lines especially near homes. In areas where there is no electricity, best available technology must be implemented such as 2g/hp/hr engines, catalytic converters, etc.

Air Quality/Environmental

- Elimination of criteria pollutants that occur with the combustion of hydrocarbon fuels (natural gas, diesel, gasoline). Displacement of emissions to power generating sources (utilities).

Economics

- The costs to replace natural gas fired compressors with electric motors would be costly.
- The costs of getting electrical power to the sites would be costly. It could require a grid pattern upgrade which could costs millions of dollars for a given area.
- A routine connection to a grid with adequate capacity for a small electric motor can be $18K to $25K/site on the Colorado side of the San Juan Basin.
- A scaled down substation for electrification of a central compression site can range between $250K and $400K.
- Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small.

Tradeoffs

- While the sites where the electrical motors would be placed would not be sources of emissions, indirect emissions from the facilities generating the electricity would still occur such as coal fired power plants.
- Additional co-generation facilities would likely have to be built in the region to supply the amount of electrical power needed for this option. This would result in additional emissions of criteria pollutants from the combustion of natural gas for turbines typically used for co-generation facilities.
- There would need to be possible upgrades in the electrical distribution system. However, the limitation of doing so is predicated by the electrical grid that would exist in a given area to provide the necessary capacity to support electrical compression

Burdens

- The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary, depending upon the results of monitoring data over time.
B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies.

III. Feasibility of the option

A. Technical: Feasible depending upon the electrical grid in a given geographic area
B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Indirect emission implications for grid suppliers should be considered (e.g., coal-fired plants).
C. Economic: Depends upon economics of ordering electrical motors, the ability of the grid system to supply the needed capacity and the cost to obtain right of way to drop a line to a potential site.

IV. Background data and assumptions used

The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff.

V. Any uncertainty associated with the option

Medium based upon uncertainties of obtaining electrical easements from landowners and/or land management agencies.

*A cumulative emissions inventory on all oil and gas field equipment is necessary
*If possible, a calculation of pollution related to electric power generation is needed for comparison to pollution emitted from gas powered engines.

VI. Level of agreement within the work group for this mitigation option

TBD.

VII. Cross-over issues to the other source groups

Oil and Gas Work Group
Cumulative Effects Work Group
Power Plant Work Group

OVERARCHING: CROSSOVER OPTIONS

Mitigation Option: Economic-Incentives Based Emission Trading System (EBETS) (Reference as is from Oil and Gas: see Oil and Gas Overarching Section)

Mitigation Option: Tax or Economic Development Incentives for Environmental Mitigation (Reference as is from Oil and Gas: see Oil and Gas Overarching Section)

FOUR CORNERS AREA POWER PLANTS FACILITY DATA TABLE

This data table was prepared by the Power Plants Work Group as a resource to help develop mitigation options. Facility data information was compiled from a variety of sources (see references). The last update of the table was August 2007. The Table, along with other resource information on Four Corners area power plants, is also available on the Task Force Website on the Power Plants Work Group Page, http://www.nmenv.state.nm.us/aqb/4C/powerplant_workgroup.html

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010 [10]
San Juan Generating Station [1]	PNM Resources (Owner/Operator)	Coal	ARP, EPA 9, Western Systems Coordinating Council	NMED - AQB	4 units, 1798 MW	PM- ESP	PM – 673 tons (2005)		PM – baghouse	13,097,406 tons (2005)	PM - 670 tons/yr
						SO_x - Wet Limestone	SO_2 – 16,570 tons (2005)	SO_2 – 16,179.3 tons (2004), 16,569.5 tons (2005) [4]	SO2 – enhanced scrubbing		SO2 - 8,900 tons/yr
						NO_x – Low-NOx burners / Over-fired air	NO_x – 26,809 tons (2005)	NO_x – 26,880.2 tons (2004), 26,809.0 tons (2005) [4]	NO_x – low-NO_x burners/ over-fired air / neural net		NOx - 18,500 tons/yr
						Hg – Wet scrubber	Hg – 766 lbs (2005)	CO_2 – 13,147,181.0 tons (2004), 13,097,410.1 tons (2005) [4]	Hg – activated carbon. Hg – CEMs		Hg - 275 lbs/yr
Four Corners Power Plant [2,3]	Arizona Public Service Company (Owner/Operator)	Coal	ARP, EPA 9	EPA Region 9, Navajo Nation EPA	5 units, 2040 MW	Units #1 - #3:	PM – 1,187 tons (2000-2005 annual average)		Considering available technologies for future regulatory changes [3]	15,913,105 tons (2000-2005 annual average)	N/A
						PM - Wet venturi scrubbers	SO_2 – 12,500 tons (2005)	SO_2 – 18,771 tons (2004), 12,554.2 (2005) [4]			

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010
Four Corners Power Plant [2,3] (cont.)						SOx - Dolomitic lime wet scrubbing	NO_x – 42,000 tons (2000-2005)	NO_x – 40,742 tons (2004), 41,743.4 tons (2005)			N/A
						NO_x – Low-NOx burners	Hg – Approx. 550-600 lbs/yr	CO_2 – 15,106,255 tons (2004), 16,015,408.7 tons (2005) [4]			
						Hg – Venturi scrubber					
						Units #4 & #5:					
						PM – Baghouses					
						SOx – Lime slurry wet scrubbing					
						NOx – Low-NOx burners					
						Hg – Wet scrubber, baghouses					
Proposed Desert Rock Energy Facility [5, 12]	Sithe Global Power, LLC (proposed owner/operator)	Coal		EPA Region 9, Navajo Nation EPA	2 units, 1500 MW [5]	PM – Baghouse [6, 12][1]	PM (TSP/PM) – 570 Tons/yr [6,12][3]		Hg – activated carbon if control < 90% and cost < $13,000/lb**	Approx. 12,700,000 tons/yr[8]	N/A
							PM_{10} – 1,120 Tons/yr [6, 12][4]				
						SOx –Wet Limestone FGD [6, 12][1]	SO_2 – 3,319 Tons/yr [6, 12]				
						NOx – low-NOx burners/ over-fired air / SCR [6,12]	NO_x – 3,325 Tons/yr [6, 12]				

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010
Proposed Desert Rock Energy Facility [5, 12] (cont.)						Hg – SCR +baghouse +FGD[2] [6, 12]	Mercury – 114 lbs/ yr [12]				N/A
							CO – 5,529 Tons/yr [12]				
						Hydrated Lime Injection & Wet Limestone FGD [12]	Lead – 11.1 Tons/yr [12] Flourides – 13.3 Tons/yr [12]				
						Hydrated Lime Injection & Wet Limestone FGD [12]	H_2SO_4 – 221 Tons/yr [12]				
Bluffview Power Plant [4]	City of Farmington (Owner/Operator) (Started 28-JUL-05)	Pipeline Natural Gas / Cogeneration	ARP, EPA 6		60 MW	Dry Low NOx Burners, Selective Catalytic Reduction		SO_2 – 0.7 tons/yr (2005) [4]		145997.3 tons (2005) [4]	N/A
								NO_x – 58.5 tons/yr (2005) [4]			
Milagro [4]	Williams Field Services (Owner/Operator)	Pipeline Natural Gas / Cogeneration	ARP, EPA 6		2 units, 61 MW [11]			SO_2 – 2.6 tons (2004), 2.5 tons (2005) [4]		498823.3 tons (2005) [4]	N/A
						NO_x – Dry Low-NOx burners		NO_x – 97.6 tons (2004), 110.2 tons (2005) [4]			

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010
Animas Power Plant [9]	City of Farmington (Owner/Operator)	Pipeline Natural Gas / Cogeneration	EPA 6, Western Systems Coordinating Council		51 MW [9]		SO2 – 0 (2005, turbine only) NOx – 54 Tons (2005, turbine) VOC – 54.3 Tons (2005, turbine) CO – 5.1 Tons (2005, turbine)				N/A
Bloomfield Generation [4]	Ameramex Energy Group, Inc. (Owner/Operator)		ARP, EPA 6								N/A
Navajo Dam Hydro Plant [9]	City of Farmington (Owner/Operator)	Water			30 MW [9]						N/A
Mustang Energy Project[7][5]	Proposed	Coal			300 MW		PM - 185 tons/yr SO_2 – 250 tons/yr NO_X - 125 tons/yr			Approx. 2,000,000 tons/yr[8]	N/A

[1] May 23, 2006 edit, info provided by Mike Farley (PNM), and in SJGS presentation for 4CAQTF, "SJGS Emissions Control Current and Future" http://www.nmenv.state.nm.us/aqb/4C/Docs/SanJuanGeneratingStation.pdf
[2] http://www.aps.com/general_info/AboutAPS_18.html [dl 5/29/06]
[3] APS Four Corners Power Plant tour handout (received 5/10/06), supplemental info provided by Richard Grimes (APS), in May 31 table edit
[4] EPA Clean Air Markets – Data and Maps Query (2004 2005 2006 Facility & Unit Emissions Reports)

[5] SITHE GLOBAL Desert Rock Energy Project FACT SHEET #1 DEC 2004 [dl 5/29/06]
[6] Application for Prevention of Significant Deterioration Permit for the Desert Rock Energy Facility, prepared by ENSR International May 2004
[7] Reference to Dave R. edits 6/2/06
[8] Desert Rock Energy Project Draft EIS Ch. 4.0 – Environmental Consequences May 2007
[9] Farmington Electric Utility Fact Sheet http://206.206.77.3/pdf/electric_utility/feus_fact_sheet.pdf (6/16/06) / NMED
[10] Info provided by Mike Farley (PNM)
[11] http://www.emnrd.state.nm.us/EMNRD/MAIN/documents/SER1_electricity.pdf
[12] AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01), Table 1, EPA Region 9 Air Programs: http://www.epa.gov/region09/air/permit/desertrock/#permit

[1] Subject to BACT - Best available control technology [6]
[2] Mercury (Hg) and HCL have been targeted under future regulation under maximum available control technology (MACT) [6]
[3] PM is defined as filterable particulate matter as measured by EPA Method 5.
[4] PM10 is defined as solid particulate matter smaller than 10 micrometers diameter as measured by EPA Method 201 or 201A plus condensable particulate matter as measured by EPA Method 202. EPA is treating PM10 as a surrogate for PM2.5.
[5] Outside of Scope of Work, Not located in 4CAQTF study area

POWER PLANTS: PUBLIC COMMENTS

Power Plants Public Comments

Comment	Mitigation Option
I have been concerned for many years about the air quality of the Four Corner's region because of the coal fired power plants in N.M. I attended two of the Four Corner's air quality forums in the past and was disturbed by their reports. As a nurse, I am especially concerned for the health of the Native Americans and other people who reside close to the power plants because of their incidence of lung disease. As a resident of La Plata canyon for 20+ years with a high mercury level, I am concerned about my own health and notice more air pollution, lack of visibility, every time I hike in the mountains. I believe for everyone's health, alternative sources of energy; e.g. solar, wind energy is a much better solution and would still serve as a revenue source to the Navajo nation. Desert Rock should not be built and the others should be phased out as planned many years ago or at least upgraded to standards that were set by the Clinton administration.	General Comment
We do NOT need another power plant in the 4 Corners. I notice the dirty air in this area all of the time and especially on weekends. Drive up from Albuquerque and see the air get dirtier. Also, go out from the 4 Corners and notice the beautiful blue skies as you progressively leave the area. I teach school and stress to my students they need to take care of the this planet earth because there is no spare earth. I would like to stress to everyone else that this needs to be done. Solar, wind and other energy sources should be used.	General Comment
It saddens me and concerns me for our children's futures and the native American leaders who think that this is progress and prosperity for their people. The leaders are once again selling out their people for the promise of temporary jobs and profits. How can we as a educated people agree to allow this plant in today's environment? Mercury in our children's blood and more carbons in the air are a horrible price to pay for short term gains in energy downstream. How can Governor Richards speak of the environment while he is silent on this issue. I will not be able to attend any public meetings and would appreciate my view forwarded if possible. I am a mother, grandmother and previous medical office manager. Most importantly, I am a voter.	General Comment
It breaks my heart to think that another coal fired plant may be added to our "pristine" 4 corners area. Even in Pagosa Springs we have some hazy smog some days, and when driving south and west of Farmington, that horrible yellow-brown cloud can be seen for miles! I was shocked to see that poisonous cloud in Monument valley, and northwest Utah. It's all pervasive now so I can't imagine what it will be like with more coal -spewing plants. We must use non polluting energy sources for the health of all of us!	General Comment

Comment	Mitigation Option
Desert Rock Energy LLC (Desert Rock) appreciates the opportunity to submit the following comments on the Four Corners Air Quality Task Force Draft Report. Desert Rock supports the Task Force's efforts to promote air quality mitigation in the Four Corners area. Desert Rock is committed to air quality mitigation, and has designed the proposed Desert Rock Facility to minimize impacts while providing needed electricity and additional economic development to the Navajo Nation. As detailed in the Draft Task Force Report, the proposed Desert Rock Facility is a 1,500 MW mine mouth power plant being developed by Sithe Global Power, Desert Rock Energy Company, and the Dinè Power Authority (an enterprise of the Navajo Nation). It is designed to burn low BTU, low sulfur subituminous Navajo coal. The plant will be located at an elevation of 5,415 feet. It will be one of the most efficient plants in the US, with two supercritical pulverized coal-fired boilers operating at a net heat rate of 8,983 Btu/kWh. The plant will be required to operate with very low emission rates, including 0.06 lb/MMBtu for both NOx and SO2 and 0.01 lb/MMBtu for filterable PM, all on a 24-hour average. The plant will also use dry cooling to reduce water consumption by 80 percent. EPA has stated that the Desert Rock Facility will have the lowest emission rates of any coal-fired project in the US. These emission rates will be even lower than emission rates associated with IGCC. Desert Rock is committed to engaging in regional air quality improvement initiatives. In fact, Desert Rock has already invested significant time and resources participating in such initiatives. Desert Rock has worked with the National Park Service, the National Forest Service, EPA, the Navajo National Environmental Protection Agency, and other governmental stakeholders to create a mitigation plan that will offset all SO2 emissions from the facility and further reduce mercury impacts. Below is a description of this regional effort: 1. Desert Rock Energy has agreed to a Voluntary Regional Air Quality Improvement Plan with the US EPA, US Forest Service, National Parks Service, and the Navajo Nation Environmental Protection Agency. 2. The Improvement Plan requires Desert Rock to reduce regional SO2 emission and visibility impacts by one of three (3) mechanisms: 1) Regional SO2 Control, 2) Regional NOx Control, or 3) Procurement and retirement of SO2 Allowances. a. Under an SO2 control-sponsored project, the implementation of this plan will result in a net improvement of the local environment. The plan, not only will totally offset the SO2 emissions of Desert Rock (3,315 tons of SO2), it will also remove an additional 330 tons of SO2 from the local atmosphere, for a total reduction of 110%. b. If an SO2 control project cannot be developed, Desert Rock may implement a NOx control-sponsored project which will remove NOx emissions in the region by 100% of Desert Rock NOx emissions plus approximately an additional 7500 tons. c. If Desert Rock is not able to invest in capital projects at other plants to reduce SO2 or NOx emissions, Desert Rock has reserved capital to purchase and retire up to $3,000,000 per year in SO2 allowances for the life of the project. The acquisition of these allowances is beyond those that are required under the Acid Rain program.	General Comment

Comment	Mitigation Option
3. Mercury control of at least 80% will be achieved. Additional investments in Mercury control technology to reach a target of 90% control will be made subject to plan limitations. If the 90 % control target is met, it will reduce mercury emissions an additional 50 percent from approximately 160 lbs per year to approximately 80 lbs per year. 4. The local area will benefit from Desert Rock's annual environmental contributions that may be available subject to plan limitations. Such contributions could be used to advance the local environmental science and planning as well as sponsor projects that reduce greenhouse gas emissions, add further mercury control, increase monitoring, support the Four Corners Task Force, or contribute to any other environmental project determined to be of great value to the region. Desert Rock objects to the language in the Draft Report stating that "[t]he uncertainty [about the mitigation plan] involves how stakeholders can be assured the measures will actually happen." Desert Rock has made a public commitment to implement this mitigation plan and, in order to reassure all stakeholders of its commitment, is in the process of working with Federal agencies and the Navajo Nation to ensure that this mitigation plan is federally enforceable. The Desert Rock Facility will therefore be held accountable for fulfilling its mitigation commitments. In light of the mitigation plan, the Draft Report is incorrect in saying that "[w]hile the Desert Rock Energy Facility is using newer environmental emission control technology that on average have higher reduction efficiencies than existing facilities, the proposed power plant will still be adding substantial NO2, SO2, particulate, and other emissions to the Four Corners Area." It is quite likely that, because of the mitigation plan, either SO2 or NOx emissions in the area will actually be reduced. Although there will be a very small increase in emissions of other pollutants, the amounts are so small that the Plant will not have an appreciable impact on air quality in the Four Corners area. Discussion of CO2 Emissions Desert Rock believes that global climate change is a very serious issue and is committed to working with governments and industries to develop laws and policies - and most importantly, advanced technologies - that will reduce anthropogenic emissions of CO2 and other greenhouse gases. Indeed, as discussed below, we are actively exploring options that may allow us to capture and sequester CO2 emissions from the plant at some point in the future. We are concerned, however, about the discussion of CO2 emissions in the Draft Report. The Report is designed to address air quality issues in the Four Corners area, and it is simply misleading to suggest that CO2 is an air quality issue. CO2 emissions in New York and New Delhi will have precisely the same impact on climate change in the Four Corners Region as CO2 emissions from Desert Rock. By addressing CO2 without making a clear distinction between air quality (which is largely a local and regional issue) and climate change (which is entirely a global issue), the Report will actually be misleading to many readers who are not fully informed about the nature of climate change.	

Comment	Mitigation Option
IGCC and Desert Rock The Draft Report includes a discussion of Integrated Gasification Combined Cycle (IGCC) technology that is not appropriate for the Desert Rock Facility. We are concerned that it will mislead readers into thinking that IGCC would be a better environmental choice for the Four Corners area, when this is simply not the case. The EPA Report cited in the Report does not address the issues involved in building an IGCC plant (or a modern supercritical pulverized coal plant) with the type of coal available in the Four Corners area or at an altitude anywhere near the elevation of the Desert Rock Facility. Not only technical experts with Desert Rock Energy, but other technical experts have concluded that there would be serious technical challenges involved in trying to operate an IGCC plant at a site like the Desert Rock Facility. The Report suggests that, at a minimum, Desert Rock should have been required to evaluate IGCC as part of the BACT process. Desert Rock did, in fact, evaluate the potential use of a range of modern coal technologies including IGCC. Nothing more would be learned by formally including such an evaluation in the BACT process. Desert Rock determined that the use of modern supercritical pulverized coal boilers is the best option, not only in terms of cost and reliability, but from an environmental standpoint as well. This technology is proven, reliable, and highly efficient and, in combination with an extensive array of pollution control equipment, will be a leader in reducing emissions from coal combustion. EPA has again stated that the Desert Rock Facility will have the lowest emissions rate of any coal-fired project in the US. As discussed below, there would be no material difference in emissions - including CO2 and other green house gas emissions - with an IGCC plant at the Desert Rock site assuming current IGCC technology performance. Though IGCC is an evolving technology, IGCC does not currently meet the need for reliable and economical power production. There are only four operating coal-fired IGCC plants in the world, two in the United States both which use petroleum coke and not coal as the fuel source. Other IGCC projects in the US were built as small scale (less than 300 megawatts) demonstration projects with substantial government funding and some faced such severe operating problems that they never reached commercial operation. Even the facilities that did achieve commercial operation have not met projections for cost, efficiency, reliability and environmental performance. The "next generation" of IGCC plants, currently in development, with commercial operation dates planned in the 2011-2015 period, are in the 300-600 megawatt range. It remains to be seen if the next generation of IGCC plants will meet the cost and reliability targets needed to provide reliable, low cost power. There are also many engineering issues that remain to be solved in using low BTU high ash coals such as those found in New Mexico to fuel IGCC plants. Reliability - The IGCC units currently in operation have a poor reliability records. It remains to be seen if the next generation of IGCC plants will face similar reliability issues. The "integrated" part of IGCC refers to the integration of a gasifier and a combined cycle power plant to transform the	

Comment	Mitigation Option
coal into syngas and combust that syngas to produce electricity. This integration introduces numerous additional potential engineering points of failure and, as a result, there is a record of poor performance. Several of the IGCC units in operation have been able to reach the 80% reliability level but only after five to ten years of operation. In contrast, supercritical technology proposed for Desert Rock has a proven performance record of 90% or better, beginning in its first year of operation. Cost - Projections of life cycle capital and operating costs for IGCC plants in the 600 to 2,000 megawatt range are substantially higher than supercritical technology. These have demonstrated that the cost of a 1,500 megawatt IGCC plant is approximately 30-40% higher than a similarly-sized supercritical pulverized coal plant. Desert Rock would cost $1 billion more built using IGCC technology. Efficiency - The technology proposed for the Desert Rock Facility is highly efficient, meaning substantially less coal is used to produce the same amount of electricity with fewer emissions than older, conventional coal fired power plants. Desert Rock's proposed technology is also more efficient than current IGCC plants. For example, the technology proposed for the Desert Rock Facility is approximately 15% more efficient than the present IGCC facilities in Florida and Indiana, meaning it will use 15% less coal to produce a similar amount of electricity on an average annual basis. In comparison to recently filed air permit applications for the "next generation" IGCC plants, the Desert Rock Facility will have comparable efficiencies when the IGCC efficiency losses of operating at above 5,000 ft above sea level are taken in account. Emissions - Due to the high efficiency of the Desert Rock Facility's generating technology and the extensive array of pollution control equipment incorporated into its design, the plant's emission rates compare very favorably to existing IGCC units and are expected to be similar to the "next generation" IGCC plants. IGCC plants do not produce any less greenhouse gasses than a supercritical plant with similar efficiency Desert Rock is also designing the facility to have "future proofing" characteristics, which allow for augmentation of the initial extensive array of emissions control equipment and with more advanced control equipment when the new equipment is demonstrated to be commercially viable. Summary on IGCC - Desert Rock carefully considered all options available before concluding that supercritical pulverized coal technology is the best choice for the facility. The Desert Rock Facility's supercritical design helps to ensure a reliable power supply and lower fuel cost for customers, while being highly protective of public health and the environment. While IGCC is expected to become a viable large scale electric generation technology in the future, it currently lacks the reliability, efficiency, economics, and scale that supercritical technology provides with no material difference in emissions including greenhouse gases Carbon Sequestration and Desert Rock Sithe Global Power, LLC continues to study the technological and commercial implications of carbon capturing and sequestration (CCS) in	

Comment	Mitigation Option
power plant applications. With respect to the Desert Rock Facility, we have participated in numerous discussions with the Department of Energy, various national laboratories, and the major equipment suppliers to evaluate the technological feasibility and economic viability of a large scale CCS project. After extensive discussions, we have been unable to identify a commercially feasible solution. As of today, the major equipment suppliers are unwilling to offer performance guarantees for a large scale CCS project. In addition, an appropriate mechanism to recover the cost of implementation, including the cost of development, installation and operation, has not yet been implemented. As a result, Desert Rock is not in a position to incorporate CCS at this time. Desert Rock intends to continue to participate in the development of CCS and will consider the implementation of CCS once the technology and commercial framework are in place. The major equipment suppliers have an economic incentive to complete the development of the necessary technology. The Task Force can provide a great deal of assistance to help create and promote an appropriate commercial framework. Thank you for the opportunity to provide the above comments on the Draft Task Force Report. Desert Rock is again committed to air quality mitigation and appreciates the Task Force's efforts. If you have any questions or we can be of assistance, please let us know. Sincerely, Dirk Straussfeld Executive Vice President Desert Rock Energy Company, LLC Three Riverway Suite 1100 Houston, Texas 77056 Phone: (713) 499-1155 Fax: (713) 499-1167	

Comment	Mitigation Option
A Mitigation Option should be added for Nuclear technology. We should not assume that it is too controversial for consideration. The U.S. Nuclear Regulatory Commission is staffing up to consider up to 30 nuclear units in fiscal 2008. This was motivated by the Energy Policy Act of 2005, that has invigorated the power industry to come forward with new plans. A new NRC office has been created solely for licensing and oversight of new reactor activities, with a current staff of 240. The most activity for these units will be in the south and southeast, where utilities have on-going nuclear experience. NRC has streamlined their processes so standard design certifications would be approved, and the safety design hurdle would not be raised continually. Most of these applications will be active pump/valve cooling designs that meet the stringent safety requirements of standard design certifications. There is promise for a family of passive cooling reactors, where gravity/density differences provide equivalent cooling protection. These designs would be simpler and less expensive than current active pump designs. Much design work has been done, although there is not currently such a unit in operation. Nuclear plants have lower maintenance costs (about 1.7 cents per kwh, v.s. 3 - 5 cents for a fossil fuel units). Operating experience has advanced greatly over the 30 years since Three Mile Island, with plants running at 90% capacity -- up from 70% in the 1970s. Benefits: Zero air emissions impact; No carbon footprint; cost effective electricity generation; foster high technology employment basis in Four Corners; proximity to future Nevada spent fuel storage site Tradeoffs: Negative public opinion; spent fuel containment Reference: Energybiz magazine Vol. 4, Issue 3 (May 07, June 07) "Agency Gets Ready for Nuclear Renaissance" -- "Repackaging the Nuclear Option" -- "GE Gears Up"	Proposed Power Plant - Desert Rock Energy Facility
I feel this (and perhaps one or two other power plants options) should be incorporated by reference into the monitoring section. There is a lot of good writing here.	Negotiated Agreements in Prevention of Significant Deterioration (PSD) Permits
The monitoring of degrading power plants deserves dual attention; both in this section and in the monitoring section for emphasis.	Negotiated Agreements in Prevention of Significant Deterioration (PSD) Permits
The Electric Power Research Institute (EPRI) today announced the beginning of a new project to study the feasibility of concentrating solar power in New Mexico. Unlike conventional flat-plate solar or photovoltaic panels, concentrating solar power (CSP) uses reflectors to concentrate the heat and generate electricity more efficiently. There are four utility-sized CSP plants in the U.S. today; one in Nevada and three in California. Initiated by New Mexico utility PNM and with subsequent interest from other regional utilities, the project will be directed and managed by EPRI. PNM has expressed interest in building a CSP plant in New Mexico by 2010. The feasibility study for a power plant of the 50-500 megawatt (MW) size range is expected to be finished by the end of 2007. The Four Corners area is one of the best areas for solar energy production in the United States and would be an ideal location for a new solar energy plant. For example, in Farmington,	Utility-Scale Photovoltaic Plants

Comment	Mitigation Option
NM a flat-plate collector on a fixed-mount facing south at a fixed tilt equal to latitude, sees an avg. of 6.3 hours of full sun. The Solar plant could help New Mexico meet renewable energy portfolio standards. San Juan County also has a renewable energy school focusing on solar energy system design and installation. The plant could potentially be an educational/technical resource for the college.	
I would emphatically like to see this option included in the final report.	Reorganization of EPA Regions
The need for these studies is obvious and the cost should be passed on to the utilities (and therefore the customers). However, even if these new studies find a significantly negative relationship between chronic respiratory disease and air pollutants, we already have proof that air pollutants increase the incidence of asthma. This mitigation option should include plans to utilize the study results for actively engaging policy-makers and changing regulations and enforcement, especially in geographic hot spots.	Chronic Respiratory Disease Study for the Four Corners area to determine relationship between Air Pollutants from Power Plants and Respiratory Health Effects

Other Sources

Other Sources: Preface

Overview

The Other Sources Work Group was charged with analyzing emissions mitigation strategies from all industrial, residential and transportation sectors that have emissions that significantly impact air quality in the Four Corners region. Although the work group was small, participation in the group involved state, local and tribal air quality agencies, industry representatives, public citizens, and representatives of environmental organizations.

Organization

The members of the Other Sources Work Group decided to focus on four main topic areas:

1. Transportation, including mobile sources
2. Land use, development, and planning
3. Burning
4. Alternative energy and fuels

Mitigation options for transportation issues included the following: including multi-modal transportation options in the 2035 transportation plan, including the Four Corners region into the Clean Cities designation for the Western Slope, encouraging local organizations to push for new projects and ordinances for transportation issues, developing requirements for anti-idling, school bus retrofits, increasing taxes for dirtier vehicles, developing a regional inspection and maintenance program, retrofitting or replacing oil and gas fleet vehicles, and looking at the Reid vapor pressure of fuels.

For land use, development and planning, the group discussed the consistency of regulations between jurisdictions for construction and sand and gravel operations, developing a regional planning organization for the region, phasing of projects to minimize blowing dust from bladed tracts of land, and developing a fugitive road dust plan.

Burning is handled very differently among the different jurisdictions in the Four Corners region. Mitigation options discussed for burning included public education and outreach, regulating agricultural burning in the Colorado portion of the region, providing a subsidy for cleaner fuels for residential heating, and using filter traps on wood stoves.

The alternative energy and fuels options were developed in conjunction with the Power Plants work group, and are included in the Energy Efficiency, Renewable Energy and Conservation section of this document.

Mitigation Option: Phased Construction Projects

I. Description of the mitigation option

Construction projects remove large quantities of vegetation leaving bare earth open to wind erosion, as well as to other environmental and biological degradation. Phasing these projects, large and even single residential development could lessen this environmental problem. Phasing re-vegetation would also result in decreased wind erosion.

Since phasing includes both small and large projects, this is something that individuals can have a part in as well as participating in for the larger community.

Benefits:

- Air quality – Particulate matter would decrease, protection of scenic views and economic benefits for tourism

- Environmental – Globally desertification is a big concern. The decrease in wind-blown particulates could delay man-made local desertification.

- Economic—construction would be phased according to building. Therefore, upfront costs would be also coordinated with sales, rather than all at the project beginning. Construction loans would also be phased.

Burdens:

- Developers may see change in methods as a threat to free enterprise.

- Construction managers would have to keep grading machinery on site locations throughout the project.

II. Description of how to implement

A. Mandatory or voluntary

Both. Mandatory for new construction. Incentives for individual homeowners to plant vegetation on disturbed sites.

B. Indicate the most appropriate agency(ies) to implement

Counties and towns in land use regulations, building permits. Local and state agencies may also implement programs for free compost or vegetation (e.g., native trees or shrubs for lot sizes over 1 acre).

III. Feasibility of the option

A. Technical – High
B. Environmental – High
C. Economic – High – may result in higher costs for construction projects in some areas.

IV. Background data and assumptions used

Help from monitoring work group to collect data downwind of

V. Any uncertainty associated with the option (Low, Medium, High) – Low

VI. Level of agreement within the work group for this mitigation option.

VII. Cross-over issues to the other source groups

Oil and gas and power plant work groups may look at phased development and revegetation for new projects.

Mitigation Option: Public Buy-in through Local Organizations to push for transportation alternatives and ordinances

I. Description of the mitigation option, including benefits and burdens.

Involve existing local organizations in supporting alternative transportation options. Go to meetings of existing organizations and discuss how they can help to promote clean air. Examples of the type of projects local organizations might support include bike paths, bike racks on buses, carpool lanes, and ride-share.

Benefits of applying this option might include reduced traffic congestion, reduction of fuel use, and boosts to local neighborhood economies. Burdens would be minimal though there may some tax increases may be necessary to fund the projects.

II. Description of how to implement

This would be a voluntary option. Agencies and task force members would implement by participation in local meetings. Publicity to encourage participation in organizations and support for alternatives might also be used. States could use these partnerships as early action compacts for State Implementation Plans.

III. Feasibility of the option

This option would be easy to implement because it is voluntary. While there may be some minimal cost for agencies to participate in local meetings it would be within their mission and a positive use of tax dollars.

IV. Background data and assumptions

The simplicity of this option requires no background analysis. It is assumed that individuals would make the effort to partner with local organizations.

V. Any uncertainty associated with the option

There is little uncertainty that this would be a viable and effective option.

VI. Level of agreement within the Work Group for this option

All work group members agree that this is a worthwhile option.

VII. Crossover issues to other workgroups

Involvement in planning for employee ridesharing may crossover to the Power Plant and Oil and Gas groups.

Mitigation Option: Regional Planning Organization for the Four Corners Region

I. Description of the mitigation option
The Four Corners region has a number of different jurisdictions and requirements. The air quality issues in the region are more widespread than local jurisdictions or agencies can address without working together as a regional planning organization (RPO). What occurs in one jurisdiction affects other jurisdictions, especially with respect to air quality. Although any one jurisdiction may have a very good program, that would be unlikely to have a widespread effect throughout the Four Corners region. The synergies of a region are much greater. In not duplicating efforts, costs will be lessened. States and local jurisdictions must be committed to the work of the RPO. RPO membership should be limited to those who have regulatory authority (e.g., towns, cities, counties, tribal governments, states).

II: Description of how to implement
Members could be appointed by local and/or state governments. Officers could be voted in by the members. Member entities would include the cities/towns of Durango, Farmington, Aztec, Cortez, Bloomfield, and Pagosa Springs; the tribes of Navajo Nation, Southern Ute, Ute Mountain Ute, Jicarilla Apache; and the counties of San Juan and Rio Arriba in New Mexico and Montezuma, La Plata and Archuleta in Colorado.

Meetings of the regional planning organization would be held on a regular schedule (perhaps quarterly) and open to the public. It is important that the governors of the Four Corners states support the organization. Local agencies would brief the governors and the state agencies on the need for a work of the organization. It is possible that this organization could be set up similarly to a Council of Governments organization. One way to begin the conversation to establish the RPO would be to ask the League of Women Voters or other task force members to present this idea to the Northwest New Mexico Council of Governments. Funding could be joint from states, tribes, local governments, and potentially EPA grants.

Another option would be to house this RPO within the Western Governors Association, perhaps similarly to the Western Regional Air Partnership with a scope limited to the Four Corners region.

III. Feasibility of option
If there are 2 or 3 local champions that are willing to dedicate time and energy, this could work. Also, support of the state agencies and governors would be critical.

IV. Background data and assumptions used Assume local governments will be willing to work together on these issues.

V. Any uncertainty associated with the option (Low, Medium, High) Medium, depending on local support.

VI. Level of agreement within the workgroup for this mitigation option Strong.

VII. Cross-over issues to other source groups
No, although it is similar in focus to the Overarching mitigation option on Reorganization of EPA Regions.

Mitigation Option: Develop Public Education and Outreach Campaign for Open Burning

I. Description of the mitigation option

This option involves the development of a public education and outreach campaign that would target the practice of open burning. The goals of this mitigation option are to 1) educate the public on the health dangers associated with open burning, 2) educate the public on the environmental/air quality damages of open burning, and 3) decrease the usage of open burning in the targeted communities.

Open burning is a more serious threat to public health and the environment than what was previously believed. Burning household waste produces many toxic chemicals and is one of the largest known sources of dioxins in the nation. Dioxins are highly toxic, long-lasting organic compounds that are extremely dangerous, even at low levels. Dioxins have been linked to serious health problems, including cancers and developmental and reproductive disorders. Other air pollutants such as particulate matter, sulfur dioxide, lead, mercury and hexachlorobenzene also affect adults and children with asthma or other lung diseases. Diseases related to the nervous system, kidneys and liver have also been linked to these pollutants.

II. Description of how to implement

A. Mandatory or Voluntary: This program would be a voluntary program hosted by local agencies or environmental groups.

B. Indicate the most appropriate agency(ies) to implement: Public Health, Environmental

III. Feasibility of the option

A. Technical: There are many similar open burning education campaigns present in Colorado, therefore it would not be difficult to receive technical support for the option.
B. Environmental: Since we are aware of the environmental dangers associated with open burning, there is much research available to use in educating the public.
C. Economic: Depending on the budget of the agencies, this program should not be prohibitive or expensive.

IV. Background data and assumptions used

1. Data on emissions from open burning was pulled from the EPA's Municipal Solid Waste Web site (www.epa.gov/msw)

V. Any uncertainty associated with the option (Low, Medium, High)

Medium

Mitigation Option: Automobile Emissions Inspection Program

I. Description of the mitigation option

Automobile emissions inspection/maintenance (IM) programs are a traditional mobile source strategy to control automotive emissions. They improve air quality through the identification and repair of high emitting vehicles. Vehicles that are repaired pollute less, improving air quality. They also get better fuel economy that contributes to reducing green house gas emissions.

Inspection/maintenance programs have been used to control automobile emissions since the early 1970s. They were originally used in New Jersey, Arizona and other states as early as 1974. They have been predominantly implemented in areas that are, or have been, out of attainment for ozone or carbon monoxide.

It is estimated that in urban areas, such as Denver or Albuquerque, motor vehicles contribute one-quarter to one-half of all the anthropogenic hydrocarbon and nitrogen oxide emissions, and three-fourths of the carbon monoxide emissions. Even in rural areas, automobiles can be a source for these emissions. Control of these emissions will reduce ozone concentrations, dependent on factors such as the NOx/HC ratio, amount of solar radiation, and meteorology/air mass movement and vertical mixing. Of importance is the fact that mobile source hydrocarbon emissions generally are higher in ozone reactivity (ability to make ozone) than other sources, such as natural gas production, thus may be important to control.

Table 1
2007 Denver metro VOC and NOx inventories
(tons per day)

	Mobile Inventory	Total Inventory
VOC	117.5	479.4
NOx	119.3	336.5

Source: CDPHE, Early Action Compact (EAC)

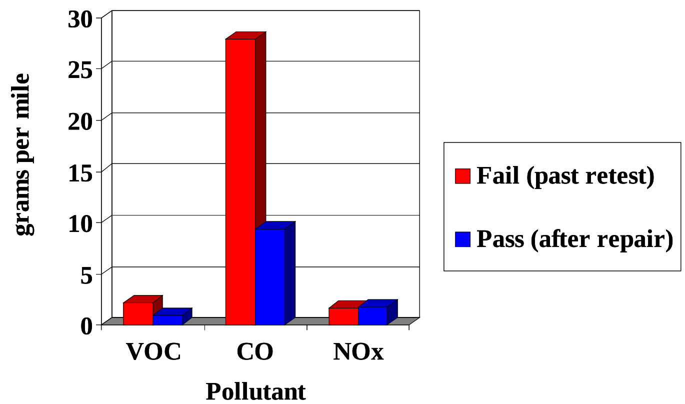
Repair Effectiveness

High emitting vehicles disproportionately contribute to mobile source emissions. Their repair is important in maintaining low overall mobile source inventories. Colorado inspection station data indicate that repairs to failing vehicles significantly reduce hydrocarbon emissions. Vehicles that failed their initial IM 240, and are later repaired, emit an average of 2.2 grams of hydrocarbons per mile. Upon passing a retest, these same vehicles emit an average of 1.0 gram of hydrocarbons per mile. This is a 57% reduction in the amount of hydrocarbons emitted by these vehicles.

Other emissions such as carbon monoxide, a weak ozone precursor, are similarly reduced. Motor vehicles that failed their initial IM 240 test, and are repaired, emit an average of 27.9 grams of carbon monoxide per mile. On a passing retest, these same vehicles emit an average of 9.4 grams of carbon monoxide per mile. This is a 66% reduction in the amount of carbon monoxide emitted by these vehicles. NOx emissions are not emphasized in Colorado’s program and are basically unchanged. Adoption of tighter NOx emission cutpoints would result in greater NOx benefit.

The repair effectiveness results of Colorado’s IM240 program are given in Figure 1.

Figure 1
2005 COLORADO IM240 TEST RESULTS
INITIAL FAILS VS FINAL PASSING TEST
ALL VEHICLES



On-Board Diagnostics

There are many different types of IM programs and IM tests. However, a simple cost-effective IM program is an on-board diagnostics (OBD) program, either as a stand-alone program for 1996 and newer model year vehicles, or one matched with an idle or other emissions test for 1995 and older vehicles. An OBD program can also be paired with an emissions test that measure a vehicle's emissions as well as examining their diagnostic codes. Examples of other emissions tests that may be paired with an OBD test are given in the attached appendix.

All 1996 and newer light duty vehicles are equipped with on-board diagnostics (OBD) technology. The intent of the OBD system is to monitor the vehicle's emissions control systems while the vehicle is in operation and detect potential problems as soon as they occur. Once a problem is detected, the system notifies the motorist by turning on a malfunction indicator light along with storing malfunction specific diagnostic information in the computer. The sensitivity of the system is programmed to detect a malfunction that may cause the vehicle's emissions to exceed 1.5 times its certification levels.

An OBD IM Program would require 1996 and newer model-year vehicles to undergo a periodic diagnostic check of all their stored trouble codes. If no malfunctions were identified the vehicle would pass. If malfunctions were identified, the vehicle would be required to be repaired. The following table identifies the IM benefit of an OBD-only program and an OBD program linked to an exhaust emissions test, in this case an IM240 test, for the Denver area fleet in 2007.

Table 2
OBD & OBD/IM240 Benefit
2007 Denver-Metro Fleet

	No I/M (gpm)		OBD only (gpm)	% Benefit		OBD w/IM240 (gpm)	% Benefit
HC	1.364		1.313	3.7		1.25	8.4
CO	13.627		12.832	5.8		11.959	12.2
NOx	1.392		1.334	4.2		1.315	5.5

Source: CDPHE, MOBILE 6 / 2007 Denver-metro fleet

II: Description of how to implement

An on-board diagnostics (OBD) program can be implemented as a contractor operated centralized IM program, or a decentralized inspection program, or decentralized inspection and repair program. State/local/or contractor staff would undertake program design, after authority for such a program is established through the state legislature and/or regulatory boards. Enforcement would be through state or local program enforcement staff. Registration denial would be the most effective way of maintaining program compliance.

III. Feasibility of option

An OBD program either with or without an emissions test is very feasible. Currently 32 states and the District of Columbia operate such a program, or will in the near future. Additionally, new innovative OBD features, such as self-standing, self-serve OBD kiosks, and loaner radio transponders are being implemented or are under development in Washington and California.

IV. Background data and assumptions used

Emission factors were generated by the U.S. EPA MOBILE 6b model. They reflect the Denver area fleet and transportation network for 2007. Repair effectiveness data is from the Colorado IM 240 program, and represents emission data derived from load-mode transient IM 240 testing. Inventories showing mobile source contribution are for the Denver metro area. Mobile sources' contribution is expected to be less in rural areas.

V. Any uncertainty associated with the option (Low, Medium, High)

Low. OBD Programs are proven strategies. A higher uncertainty exists for add-on elements such as implementation of self-standing, self-serve OBD kiosks, and loaner radio transponders. The greatest uncertainty is the integration of the data network with vehicle registration records and county clerk renewal processes. In states, such as Colorado, with existing IM Programs this is not an issue.

VI. Level of agreement within the workgroup for this mitigation option Good general agreement.

VII. Cross-over issues to other source groups

IM (inspection/maintenance) programs offer the ability to assist in controlling mobile source contributions to ozone formation, regional haze, air toxics, and global warming. There will be little cross-over issues with other groups. An IM program could affect gasoline vehicles used in oil and gas production, or other work covered by other groups, but generally there will be minimum cross-over.

As diesel vehicles and off-road vehicles are equipped with OBD features, they could conceivably be included in their own OBD programs. On-road diesels registered in the Front Range of Colorado currently participate in an opacity IM program.

Appendices

Significant Emissions Tests

On-Board Diagnostics

This technology is installed on 1996 and newer light-duty cars and trucks. It uses the vehicle's computer to identify potential emissions problems. If a problem exists, the system is required to warn the driver by displaying a warning light. Also, a "fault code" is simultaneously stored in memory identifying the problem area. Drivers are required to visit a test station periodically to have their vehicles "scanned" for fault codes This takes only a short amount of time. There is good accuracy in detecting potential problems with this test.

Idle Test
Initially used in New Jersey, Arizona and other states as early as 1974, emissions measurements take place while the engine is at the steady-state condition of idle. Over the years, minor changes were introduced and there are now six different idle test "types." Colorado first used this test in 1981 and still uses a modified version on heavy-duty vehicles, and older light-duty vehicles, in the Denver metropolitan program area. The major advantage of these tests is the relatively low equipment costs ranging from $15,000 to $20,000. The major drawback is a high level of false "passes" caused by newer technology on today's vehicles.

Acceleration Simulation Mode
In an attempt to increase accuracy, this newer class of steady-state test uses similar analytical equipment to the idle test, but also includes a dynamometer to "load" or "exercise" the vehicle at a constant speed. This test is designed primarily for states that are not in attainment for ozone.

A good example of the load applied to the vehicle during testing would be comparable to driving at a steady speed of 15 miles per hour on an eight percent grade hill, similar to the section of I-70 between the Morrison and Lookout Mountain exits, or at 25 miles per hour on a five percent grade hill, about half as steep as the previous example. The intent is to simulate an acceleration of the vehicle.

The two major positive elements of this test are the addition of nitrogen oxide emission measurements, and moderate equipment costs of $35,000 to $60,000.

Transient Tests
This class of test also utilizes a dynamometer but uses significantly more accurate analytical equipment and varies the vehicle speed during the inspection. The dynamometer load applied to the vehicle drive train is more similar to actual driving on a road. Test accuracy is the major positive element, with high equipment costs, often more than $100,000 being the major drawback. Because of the cost, transient tests usually are centralized due to economies of scale. The following major options are examples of transient tests.

IM 240
The IM 240 (Inspection and Maintenance, 240 seconds) is a shortened version of the Federal Test Procedure and is used in the Denver metropolitan program area. Vehicle speed is varied between 0 and 57 miles per hour. This test generally is considered to be the best predictor of the Federal Test Procedure.

IM 93
A shortened version of the IM 240, the IM 93 incorporates only the first 93 seconds. Top speed is approximately 36 miles per hour.

BAR 31
The BAR 31 (California Bureau of Automotive Repair, 31 seconds) is another loaded mode test, which has a maximum speed of 30 miles per hour and a driving time of 31 seconds, which can be repeated up to four times before failing the vehicle.

Other Predictive Options

Vehicle "Profiling"
Vehicle profiling runs in parallel with an existing inspection program. Using current inspection information, it is possible to predict whether a vehicle is likely to pass or fail based on the year, make and model. This increases the cost effectiveness of the inspection program by reducing the amount of resources needed for a full inspection test.

Low Emitter Profile
This method attempts to identify vehicles that are likely to be relatively "clean" vehicles or very low emitters. This can be done by analyzing current inspection data and predicting the probability that a certain year, make and model vehicle will pass the test.

High Emitter Profile
This method generally attempts to identify vehicles that are likely to be "dirty" or high emitters. Once identified, either through past inspection records of a specific vehicle, or because certain years, makes and models tend to be high polluters, targeted vehicles are subject to special treatment. Usually, this includes restricting the vehicle inspections to stations with higher quality control procedures and/or increasing the test frequency, e.g., substituting an annual inspection cycle for what would normally be a biennial cycle. Colorado does not use high emitter profiling in its inspection program.

Remote Sensing Clean Screen
Rather than trying to shorten or enhance a state's emission test, this technology attempts to "pre-screen" a vehicle as it drives by a remote sensing device placed on a roadside. If multiple readings indicate the car or truck is a low polluter, the vehicle owner is exempted for one test cycle from having to visit a traditional test station. The major benefit of this program is reduced inconvenience to owners of low polluting vehicles. A drawback is that some vehicles may be exempted that would normally fail the emissions test. However, by monitoring test conditions, this can be kept to a reasonable level that still meets air quality objectives. Additional issues are described in the body of this report.

Remote Sensing High Emitter Identification
As a vehicle drives by a remote sensing device, its emissions are measured. Vehicles with high enough emissions are required to come in for a confirmatory IM inspection.

Model Year Exemption
Another method of Low Emitter Profiling is exempting by model year. For instance, it is extremely unlikely that a new vehicle will fail an emissions test during the first few years from when it was manufactured. The case has been made that it is a waste of inspection resources and an owner's time to test those vehicles. Colorado exempts new cars from testing requirements for four model years.

Mitigation Option: Low Reid Vapor Pressure (RVP) Gasoline

I. Description of the mitigation option

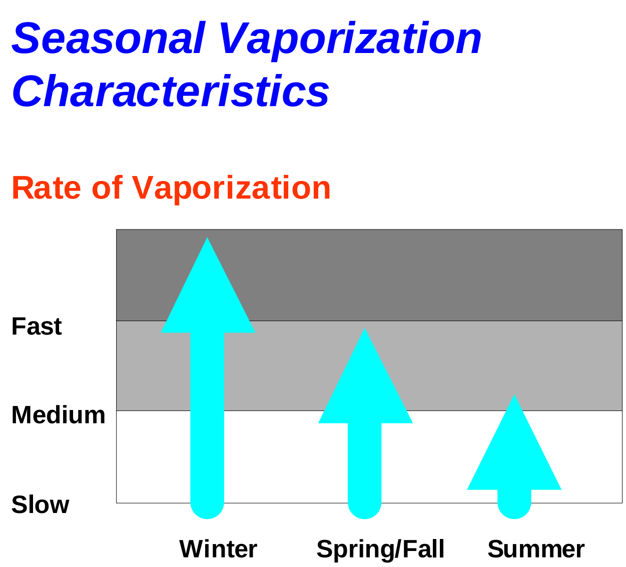
A major source of hydrocarbon emissions is the evaporative emissions produced by gasoline. Evaporative emissions occur during the refining process, through transportation and storage to the service station, and finally in refueling and operation of motor vehicles. The rate at which these emissions are produced is directly related to the fuel's volatility. The higher the volatility of the gasoline, the more volatile organic compounds (VOCs) are emitted at any given temperature.

One method to control gasoline evaporative emissions that contribute to ozone formation is to lower the volatility of gasoline, especially during the summer months. For most areas, summertime volatility is controlled by the U.S. Environmental Protection Agency (U.S. EPA). Under the Clean Air Act Amendments of 1990, the administrator of the U.S. EPA is charged with designating volatility standards for areas based on their air quality needs.

The U.S. EPA has set a gasoline volatility standard of 9.0 pounds per square inch (9.0 lbs.) for northern areas that meet the National Ambient Air Quality Standard for ozone. Air quality agencies with non-attainment areas may choose a different standard in their State Implementation Plan (SIP), or use the default standard set by the U.S. EPA.

Volatility outside the U.S. EPA controlled summer season (May 1st through September 15th) is generally controlled in most states by the American Society of Testing and Materials (ASTM) standards. These standards are set by national committees to reflect standards needed for good automotive operation and drivability.

Generally speaking, higher RVP is useful during the colder winter months to allow for easy cold weather starting and operation. Lower volatility is required during the warmer months, including summer, to prevent vehicle vapor locking and decreased drivability. The following chart shows this relationship.



SOURCE: Changes in Gasoline III

Air Quality Benefits of Lower Volatility Gasoline

As part of its efforts to reduce summertime ozone, the Denver area examined the benefits of lower volatility of gasoline. This analysis, part of Colorado's Early Action Compact (EAC) found that reducing gasoline RVP from 9.0 pounds per square inch (lbs.) to 8.1 lbs. would reduce mobile source evaporative emissions by 10 tons of VOC per day. Lowering gasoline volatility still further to 7.8 lbs. was found to reduce evaporative emissions by 13 tons of VOC per day. This represents a 7.8% to 10.2% VOC reduction in mobile source emissions.

Table 1
2007 Denver Metro VOC Inventories
(tons per day)

Reid Vapor Pressure	Mobile Inventory	Mobile Source Benefit	Total Inventory
9.0 lbs.	128	0	489
8.1 lbs.	118	10	479
7.8 lbs.	115	13	476

Source: CDPHE, Early Action Compact (EAC)

Cost

In examining the use of lower volatility gasoline to reduce VOC emissions, it was estimated that the price of gasoline would be expected to increase by one or two cents per gallon. For the Denver area it was estimated that this would equate to $8,600 per ton for 8.1 lb. RVP gasoline and $13,300 per ton for 7.8 lb. RVP gasoline. Because of high ozone measurements in the summer of 2005, and the fact that Denver had been originally been designated as a 7.8 lb. RVP area by the EPA administrator in the early 1990s (though had a received a series of waivers from this requirement), the U.S. EPA reestablished the 7.8 lb. RVP requirement for the Denver area starting with the summer of 2004.

Outside of the Denver area, all of Colorado continues to have a 9.0 lb. RVP maximum for gasoline sold between June 1st and September 15th. Most of Utah (outside of Davis and Salt Lake counties) also has this summer maximum, as does New Mexico and most of Arizona (outside of part of Maricopa County). The following chart, taken from EPA's report, "Study of Unique Gasoline Fuel Blends (Boutique Fuels) Effects on Fuel Supply and Distribution and Potential Improvements," U.S. EPA 2001, diagrams the various summertime fuel specifications for different regions of the U.S.

Summertime Gasoline Requirements

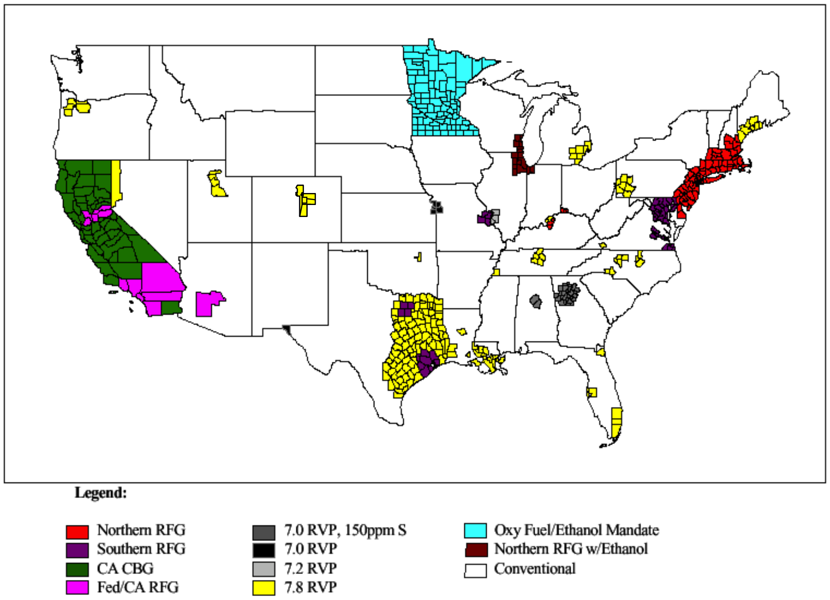


FIGURE II-1: Current Summer U.S. Gasoline Requirements

SOURCE: "Study of Unique Gasoline Fuel Blends ('Boutique Fuels'), Effects on Fuel Supply and Distribution and Potential Improvements" U.S. EPA Oct. 2001

II: Description of how to implement

Implementation of a low RVP program would be through State Implementation Plans. The various states would examine the options available, depending on air quality classification. If low RVP was required as a state program, the state would enforce the requirements. If it was an U.S. EPA program, the federal government would enforce.

III. Feasibility of option:

This option is fairly easy to develop and implement.

IV. Background data and assumptions used

A major assumption is that the Four Corners area will become nonattainment for summertime ozone, either as a result of elevated measurements, or the implementation of a new, lower, more rigorous ozone standard.

V. Any uncertainty associated with the option (Low, Medium, High) Low.

VI. Level of agreement within the workgroup for this mitigation option Good general agreement.

VII. Cross-over issues to other source groups

There does not seem to be much cross over.

Mitigation Option: Use of Reformulated Gasoline

<u>I. Description of the mitigation option</u>

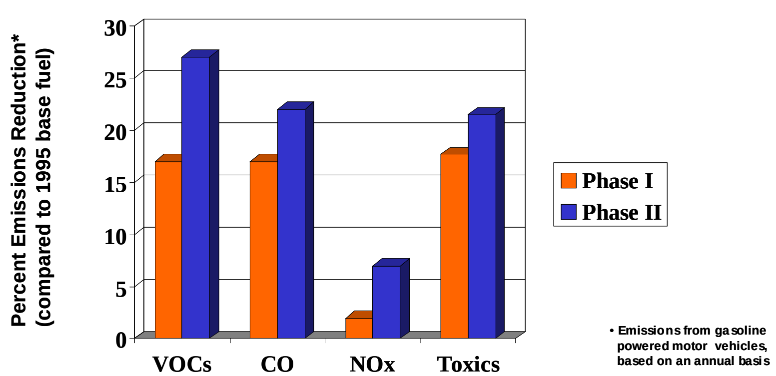
The use of reformulated gasoline (RFG) is an effective way of reducing ozone precursors from gasoline powered motor vehicles. Their use was first mandated in the nine most severe ozone nonattainment areas by the Clean Air Act Amendments of 1990. These areas included: Los Angeles, San Diego, Chicago, Houston, Milwaukee, Baltimore, Philadelphia, Hartford, and New York City. Others areas have since "opted" into the federal program. At last count, there are now 17 states and the District of Columbia that require its use. California implemented its own program beginning in 1992.

Reformulated gasoline is gasoline that has been reformulated to lower ozone precursors. While gasoline is generally formulated for the time of year or season, geographical location, altitude, and other conditions, reformulated gasoline is specifically formulated for emissions. Usually the distillation curve of the fuel (including Reid vapor pressure) is adjusted as well as other properties (light ends, olefin and aromatic content, etc.). By Clean Air Act requirement, an oxygenate, such as ethanol, is added. California reformulated gasoline goes an additional step in weighing hydrocarbon ozone forming reactivity in their performance-based standards.

Air Quality Benefits

Under the original federal specifications, the use of federal Phase I reformulated gasoline (1995) was expected to reduce hydrocarbon and air toxic emissions by 15% compared to conventional gasoline. Phase II reformulated gasoline (2000) was mandated to reduce hydrocarbon and air toxic emissions by approximately 22%.

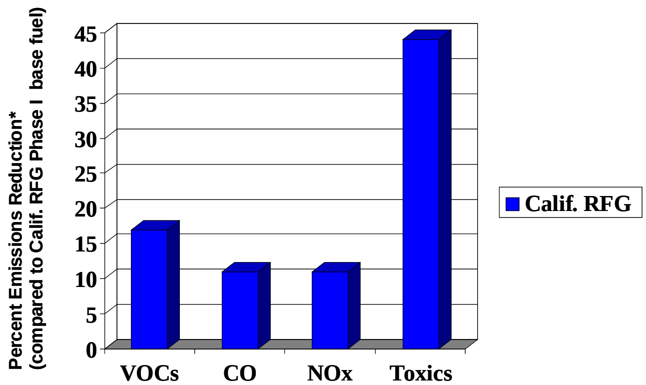
Emissions Impacts of RFG Phase I vs. RFG Phase II



Source: US EPA,"Phase 11 Reformulated Gasoline: The Next Major Step Toward Cleaner Air", Nov 1999, except for air toxics, EIA/DOE

California (CA) reformulated gasoline is even a more stringent formulation. The latest Phase 3 reformulated gasoline standards, based on the CaRFG3 predictive model, are 11% to 17% lower in HC, CO, and NOx emissions and 44% for air toxics compared to the original Phase 1 specifications introduced in 1992, itself a low ozone and air toxics formulation with caps on olefin and benzene content.

Emissions Impacts of Calif. RFG Phase II/III vs. Calif. RFG Phase I



Source: Chevron: "Gas and Air Quality: Reformulated Gasoline", Chevron

California Phase 2 reform (introduced in 1996) was estimated by the California Air Resources Board (CARB) to be twice as effective as Phase I federal reform of the same era. Phase 3 reformulated gasoline is very similar to CA Phase 2 in emissions, but does not use methyl tertiary-butyl ether (MTBE), an oxygenate found to contaminate groundwater if released during fuel spills or leaks.

Cost

Reformulated gasoline is more expensive than conventional gasoline to produce (though this is less so with the implementation of federal Tier II conventional gasoline requirements beginning in 2005). The U.S. EPA estimated that Phase I federal reformulated gasoline typically cost between three and five cents per gallon more to produce than conventional gasoline, with Phase II reform costing an additional one to two cents. CARB estimated California reformulated Phase 2 gasoline to be between five and fifteen cents per gallon more expensive than conventional gasoline.

Supply issues come into play with reformulated gasoline. While most refineries can easily make it, their facilities may not always be optimized to produce it. California reform is even more subject to these limitations.

Approximately 30% of all gasoline now sold in the United States is reformulated. The following chart, taken from EPA's report, "Study of Unique Gasoline Fuel Blends (Boutique Fuels) Effects on Fuel Supply and Distribution and Potential Improvements," U.S. EPA, 2001, diagrams the various reformulated gasoline program areas, as well as summertime fuel specifications for different regions of the U.S.

Summertime Gasoline Requirements

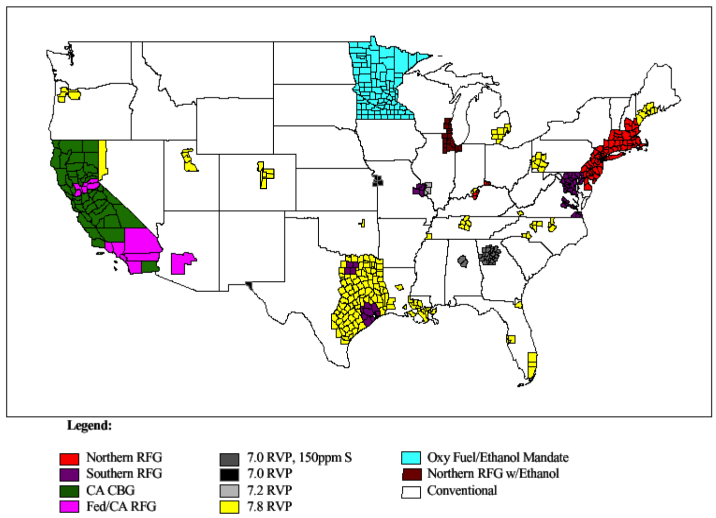


FIGURE II-1: Current Summer U.S. Gasoline Requirements

SOURCE: "Study of Unique Gasoline Fuel Blends ('Boutique Fuels'), Effects on Fuel Supply and Distribution and Potential Improvements" U.S. EPA Oct. 2001

II: Description of how to implement

Implementation of a RFG program would be through State Implementation Plans. The various states would examine the options available, depending on air quality classification. Typically a state will "opt" in to the federal reformulated gasoline program, with the federal government enforcing the program. If so desired the state may implement and enforce their own state RFG program. However, state programs must be identical to federal or California RFG programs.

III. Feasibility of option

This option is fairly easy to develop and implement.

IV. Background data and assumptions used

A major assumption is that the Four Corners area will become nonattainment for summertime ozone, either as a result of elevated measurements, or the implementation of a new, lower, more rigorous ozone standard.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium. The use of reformulated gasoline would require that there be available supplies. A major refiner close to the four-corners area, Valero's McKee refinery located in the panhandle of Texas, already manufactures reformulated gasoline for Texas and other reformulated gasoline markets. The question is whether it and other refineries have the capacity, at a reasonable cost, to produce enough RFG for the Four Corners area.

VI. Level of agreement within the workgroup for this mitigation option

Good general agreement.

VII. Cross-over issues to other source groups

There does not seem to be much cross over.

Mitigation Option: Idle Ordinances

I. Description of the mitigation option
Motor vehicle idling is a source of preventable mobile source emissions. Recognizing that most vehicles do not need to idle, many cities have passed local ordinances banning excessive vehicle idling, specifically for heavy-duty vehicles such as trucks and buses. Voluntary idling programs may also be used, especially for gasoline powered light-duty vehicles.

Most city ordinances set the maximum idling time at two to five continuous minutes. Some have longer time limits. In Maricopa County, Arizona the time limit is five minutes. In Denver and Aurora, Colorado the time limit is 10 minutes in any one-hour period. Philadelphia has a minimum two minutes. The Houston/Galveston nonattainment area has a minimum of five minutes from April 1st through Oct. 31st. Salt Lake City permits up to 15 minutes of continuous idling.

Emissions Reductions
Idling ordinances generally target heavier diesel trucks and buses and particulate (PM) emissions. However, there is no reason to preclude light-duty gasoline vehicles. All internal combustion vehicles emit pollutants and green house gases. It is estimated that larger trucks and buses burn from one-half to one gallon of fuel per hour of idling (1,2), all of which produce unnecessary emissions. Light-duty gasoline vehicle fuel consumption may be half to a quarter of this.

According to Air Watch Northwest, a consortium of air quality management agencies in Washington state, Oregon, and British Columbia (www.airwatchnorthwest.com), cars at idle emit a comparable amount of pollution to when it is driven (3). This is especially true when a vehicle is started cold, before its catalytic converter is warm enough to become effective. Once warm, a catalyst will stay warm for quite some time, so shutting down an engine to conserve fuel and limit emissions will generally have little effect on catalytic effectiveness when the vehicle is restarted.

The following tables list the average emission for vehicles at idle. The first two are for passenger cars and light trucks. The third table lists emissions for heavy-duty trucks and buses. Data is from April 1998. The acronyms used in the charts are listed below. All data is from U.S. EPA, and may be obtained at: http://www.epa.gov/otaq/consumer/f98014.pdf

LDGV	Light-duty gas vehicle
LDGT	Light-duty gas truck
HDGV	Heavy-duty gas vehicle
LDDV	Light-duty diesel vehicle
LDDT	Light-duty diesel truck
HDDV	Heavy-duty diesel vehicle
MC	Misc

U.S. EPA Estimated Idle Emissions
for Passenger Cars and Light Trucks

Summer Conditions (75 degrees F., 9.0 psi Rvp gasoline)

Pollutant	Units	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
VOC	g/hr	16.1	24.1	35.8	3.53	4.63	12.5	19.4
	g/min	0.269	0.401	0.597	0.059	0.077	0.208	0.324
CO	g/hr	229	339	738	9.97	11.2	94.0	435
	g/min	3.82	5.65	12.3	0.166	0.187	1.57	7.26
NOx	g/hr	4.72	5.71	10.2	6.50	6.67	55.0	1.69
	g/min	0.079	0.095	0.170	0.108	0.111	0.917	0.028

Winter Conditions (30 degrees F., 13.0 psi Rvp gasoline)

Pollutant	Units	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
VOC	g/hr	21.1	30.7	44.6	3.63	4.79	12.6	20.1
	g/min	0.352	0.512	0.734	0.061	0.080	0.211	0.335
CO	g/hr	371	487	682	10.1	11.5	94.6	388
	g/min	6.19	8.12	11.4	0.168	0.191	1.58	6.47
NOx	g/hr	6.16	7.47	11.8	6.66	6.89	56.7	2.51
	g/min	0.103	0.125	0.196	0.111	0.115	0.945	0.042

U.S. EPA Estimated Idle Emissions
for Heavy –Duty Trucks and Buses

Engine Size	Emissions
Light/Medium HDDVs (8501-33,000 GVW)	2.62 g/hr (0.044 g/min)
Heavy HDDVs (33,001+ GVW)	2.57 g/hr (0.043 g/min)
HDD buses (all buses, urban and inter-city travel)	2.52 g/hr (0.042 g/min)
Average of all heavy-duty diesel engines	2.59 g/hr (0.043 g/min)

These average idle emissions may be compared to average vehicle emissions by comparing the first two tables with the table listed below. This data may be obtained at:
http://www.epa.gov/otaq/consumer/f00013.htm

U.S. EPA Emissions Facts
Average Annual Emissions and Fuel Consumption
for Passenger Cars and Light Trucks

Component	Car Emission Rate Fuel Consumption	Light Truck Emission Rate Fuel Consumption
HC	2.80 g/mi	3.51 g/mi
CO	20.9 g/mi	27.7 g/mi
NOx	1.39 g/mi	0.81 g/mi
CO2	0.915 lbs/mi	1.15 lbs/mi
Gasoline	0.0465 gal/mi	0.0581 gal/mi

As can be seen by a comparison of the above tables, for volatile organic compounds (VOCs), it will take eight minutes of idling to equal one mile of driving for an average automobile during the summer. For carbon monoxide (CO) this is approximately five and a half minutes, and, for nitrogen oxides (NOx) this is approximately seventeen and a half minutes.

Particulate Emissions
One reason to adopt idling ordinances or some voluntary program to reduce idling is the exposure to particulate emissions. One of the principle sources of particulate matter (PM) exposure is from diesel vehicles. This is of utmost importance when it comes to school-age children and their exposure to diesel school bus particulate and air toxic emissions. On average, children and adults may be exposed to excessive levels of PM from idling diesel trucks and buses. As the above table points out, an average heavy-duty diesel truck or bus will produce approximately 2.6 grams of particulates per hour. It should be noted that federal health-based PM standards are measured in the micrograms (not grams) range. The short term PM standard for PM_{10} is $150 ug/m^3$ for a 24-hour average.

Technologies Used to Reduce Truck Idling
A number of strategies can be used to assist vehicles, mostly trucks and buses, from needing to idle while maintaining heating and cooling capacity. For larger trucks and buses, stand-alone direct-fired heating devices are available that cost from $1000 to $2000. Automatic engine idling devices may also be used that continue air conditioning when the engine is turned off at a cost of $1000 to $2000. Most expensively, small power generating auxiliary power units may be used, each costing from $5000 to $7000 (2).

At truck stops, fleet locations, and other stationary parking facilities, truck-stop electrification may be utilized. "Shore power" is provided directly to the parked truck, linking it to the power grid for all its electrical needs. This is estimated to cost $2500 per truck space and another $2500 per truck to modify so that it can receive the electricity (2).

References:
(1). U.S. EPA
(2). Philadelphia Diesel Difference Working Group
(3). Air Watch Northwest

<u>II: Description of how to implement</u>
Generally local government may adopt ordinances limiting vehicle idling, principally heavy-duty diesel truck or bus idling. School districts can modify their procedures to prevent excessive school bus idling. Trucking fleets, including oil and gas extraction fleets can also implement updated policies for their drivers.

Local air planning agencies, state, or local government can also implement voluntary programs, aimed at both light-duty gasoline vehicles as well as heavy-duty diesel vehicles. Voluntary programs can be established relatively easily and in a minimal amount of time. Infrastructure to promote auxiliary power for trucks to use at truck stops, distribution centers (think Walmart), etc., would take more time and money to accomplish.

<u>III. Feasibility of option</u>
This is a very feasible option. Idling ordinances and voluntary idling reduction programs have been established for a number of years in many locations.

<u>IV. Background data and assumptions used</u>
Emission estimates are generally those published by the U.S. EPA.

V. Any uncertainty associated with the option (Low, Medium, High)
Low. Idling ordinances and voluntary idling reduction programs are proven strategies.

VI. Level of agreement within the workgroup for this mitigation option
Good general agreement.

VII. Cross-over issues to other source groups
There will be little cross-over issues with other groups, except for fleets, such as involved in oil and gas extraction.

Mitigation Option: School Bus Retrofit

I. Description of the mitigation option

One of the most significant sources of particulate and air toxic exposures that young school-age children are exposed to are diesel school bus emissions. Older diesel school buses contribute a greater proportion of particulate (PM), as well as nitrogen oxide (NOx) and hydrocarbon (HC) emissions, compared to current buses built to the newest emission certification standards.

While the newest school bus emissions standards have just been implemented, school buses have long lives, permitting older higher emitting school buses to continue to expose children to high levels of diesel exhaust and to contribute to summertime ozone precursors. Reducing emissions from these buses will result in emission reductions that will last for years.

One method of reducing emissions from these older school buses is through school bus retrofit programs. Retrofit programs achieve their air quality benefit by improving the emissions characteristics of the existing school bus. Improvements may range from re-powering school buses with new replacement engines, or adding better emission control equipment, to using cleaner sources of fuel.

Emissions Reductions

PM Emissions

It is estimated by the U.S. EPA that oxidation catalytic converters retrofitted to buses reduce PM emissions by 20% to 30%, at a cost of $1000 to $2000 per bus(1). Retrofitting with a particulate trap reduces particulate matter by 60% to 90%, at a cost of $5000 to $10,000 per bus(1).

The use of ultra-low sulfur diesel fuel (required since 2006) allows these components to be added without the sulfur in diesel fuel contaminating the retrofitted equipment with a consequential loss in efficiency or damage. Ultra-low sulfur diesel fuel (maximum of 15 ppm sulfur content) is by itself expected to reduce particulate emissions by 5% to 9% (1).

Natural gas fueled school buses, if done correctly, can reduce particulate emissions by 70% to 90% at an additional cost of approximately $30,000 per bus(1). Replacement engines could reduce particulate emissions by 95% (2) as well as substantially reducing HC and NOx emissions.

Hydrocarbon and Carbon Monoxide Emissions

For ozone precursors, oxidation catalytic converters can reduce HC emissions by up to 50%. Carbon monoxide emissions may be reduced by up to 40%(2). Particulate traps will give some benefit, but are principally designed to lower particulate emissions.

The use of biodiesel fuel does reduce HC emissions, though its use will tend to increase NOx emissions (B20 up to 2%, B100 up to 10%(1)). Depending on the technology used, natural gas fueled school buses substantially lower NMHC. The U.S. EPA estimates NMHC emissions are reduced by 60%(1). NOx emissions, especially if lean-burn natural gas engines are used, may be lowered by a comparable amount. New technology replacement engines, built under the newest emissions certification standards would have substantial HC+NOx emission reductions.

The U.S. EPA has a technology Options Chart that they developed for their Clean School Bus USA Program. It lists the various technology options, their costs, and their benefits. It can be accessed at: http://www.epa.gov/cleanschoolbus/technology.htm.

Sources:
U.S. EPA Clean School Bus USA
Illinois Clean School Bus Program

Funding
There are various sources of funding for school bus retrofit programs. The U.S. EPA has annually funded retrofit programs. In 2007 they received seven million dollars under continuing resolution (H.J.R. 20) to fund projects nationwide. Eligible applicants that may apply for these funds include: state and local government, federally recognized Indian tribes, and non-profit organizations. Other sources of funding and grants include federal Congestion Mitigation and Air Quality (CMAQ) Program funds.

II: Description of how to implement
Local air planning agencies, state, or local government can implement these programs. Generally, they are funded through grants or other funding sources. They can be established relatively easily, with the needed outside infrastructure currently in place.

III. Feasibility of option
This is a very feasible option. School bus retrofit programs are operating throughout the United States.

IV. Background data and assumptions used
Emission reductions are generally those published by the U.S. EPA.

V. Any uncertainty associated with the option (Low, Medium, High)
Low. School Bus Retrofit Programs are proven strategies

VI. Level of agreement within the workgroup for this mitigation option
Good general agreement.

VII. Cross-over issues to other source groups
There will be little cross-over issues with other groups.

Mitigation Option: Subsidy Program for Cleaner Residential Fuels

I. Description of the mitigation option

Many families and individuals are forced by circumstances (economic, lack of availability, insufficient fuel delivery infrastructure, etc.) to use less than desirable fuels for cooking and heating. Many of these fuels, such as wood burning, emit high levels of toxic, or harmful, emissions, and carbon monoxide, hydrocarbon and organic compounds that are ozone precursors.

An option to reduce emissions that contribute to increased VOC, PM, CO, and air toxics is to promote the use of less polluting home heating and cooking fuels, especially electricity, propane, and natural gas in place of wood, coal, and kerosene. If wood is to continue to be used for home heating, at least a high efficiency EPA Phase II certified stove should be used.

Subsidizing Increased Cost of Fuel

Subsidizing the use of propane, natural gas, or electricity may allow low-income families to utilize these fuels in place of wood burning or other fuel sources, such as coal. Subsidy could be pegged to the economic need of the family, much like other welfare programs.

Home Heating

Replacing a traditional, non-certified wood stove with an oil furnace will reduce particulate (PM) emissions by over 99%, from 18.5 g/hr to 0.07 g/hr. Replacement with a natural gas furnace would reduce PM emissions even further to 0.04 g/hr (2).

The use of oil or gas furnaces in place of wood stoves would also have a substantial effect on carbon monoxide and emissions of hydrocarbons and other organic compounds, many of which have high ozone reactivities, as well as being fairly toxic gases. Encouraging the use of substituting electric or gas heat for cooking would similarly give a comparable emissions benefit.

New York State Environmental Protection Bureau estimates that a typical high efficiency (90%) gas or oil forced hot air furnace costs approximately $2690. This compares to a new EPA certified, catalytic equipped wood stove at approximately $2425, with a 72% efficiency rating (2).

Cleaner Wood Stoves

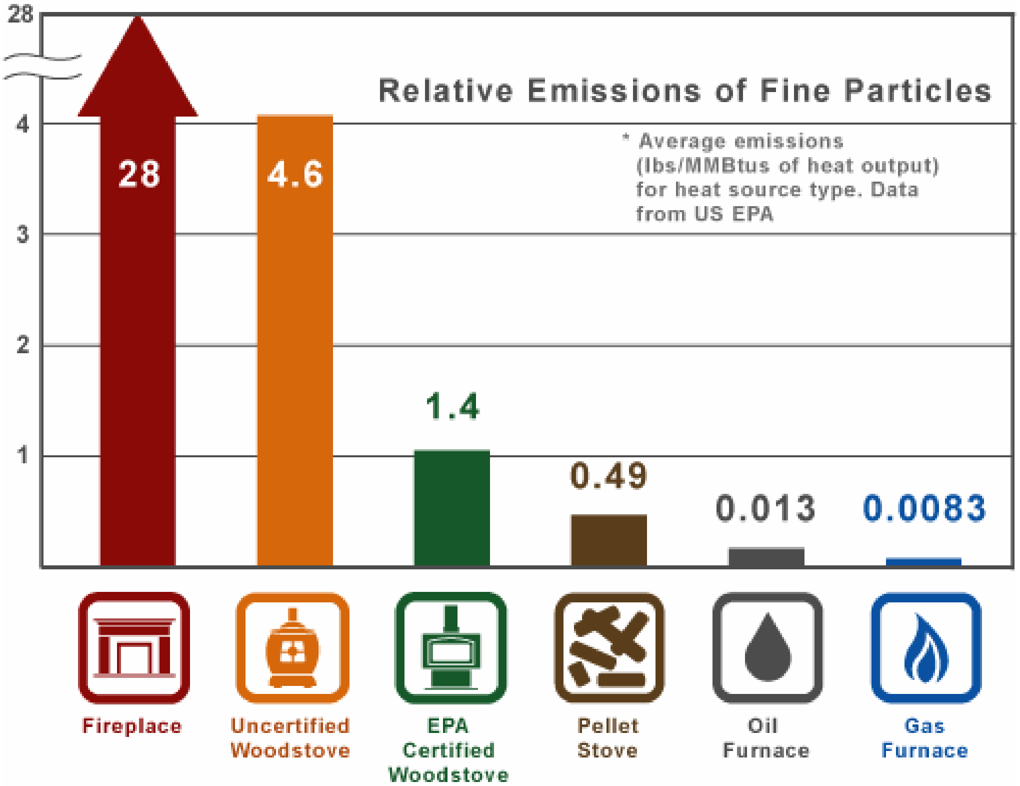
If a woodstove were used, it should be a new EPA certified one that would be expected to reduce fine particulate emission by 70% compared to an older non-controlled stove. Polycyclic aromatic hydrocarbons would be expected to go down from 0.36g/hr to 0.14 - 0.15 g/hr for EPA Phase I certified stoves to less than that for EPA Phase II certified stoves (2).

Nationwide, wood burning accounts for nine percent of home heating needs. However, it accounts for 45% of all particulate emissions from home heating (2). U.S. EPA Phase II standards are 7.5 g/hr PM for non-catalytic equipped stoves, and 4.1 g/hr PM for catalytic equipped ones (1,2). These standards are designed to reduce woodstove emissions by 60% to 80%(1).

In replacing an older uncontrolled stove with a new EPA certified stove, it is important to use an outside source of air for the heater box for combustion proposes. This prevents the stove from depleting a room's oxygen content, as well as preventing emissions from entering the house. Stoves should also have catalytic converters to ensure the lowest emissions. Common models currently may produce from 35,000 to 100,000 BTU, and are able to heat rooms from 400 to 2000, or more, square feet(3). US EPA has a website at: http://www.epa.gov/woodstoves, where more information may be obtained.

Chart One
Relative Emissions of Fine Particulates
(Grams per Hour)

U.S. EPA Chart



Source: U.S. EPA

Reference Sources:
(1). U.S. EPA
(2). New York State Environmental Protection Bureau
(3). Chimney Sweep, Inc.

II: Description of how to implement

This program may be organized much like Low Income Energy Assistance programs. A means test or other criteria could be established to prioritize available funding.

Funding this program, or set of programs, may include tax incentives, or other methods, such as voluntary grants from the natural gas extraction industry, mineral surtaxes, or drilling and permit fees. Enforcement penalties could also be used.

III. Feasibility of option

The program is very feasible. It would not only reduce emissions that could aggravate ambient ozone, PM, and CO, but would reduce toxic exposure to inhabitants of the house and nearby homes.

IV. Background data and assumptions used

It is assumed that there is a sufficient population that would benefit from an assistance program.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium. Such a program, unless funded voluntarily as a public outreach program by industry, may require additional statutory authority, requiring legislative action, as well as well as regulatory development and adoption.

VI. Level of agreement within the workgroup for this mitigation option

Good general agreement. The option was agreed upon by the workgroup without dissent.

VII. Cross-over issues to other source groups

There are no cross-over issues identified at the present time.

Mitigation Option: Stage One Vapor Recovery

I. Description of the mitigation option:
Mandatory use of stage-one vapor recover systems will reduce evaporative emissions from service stations.

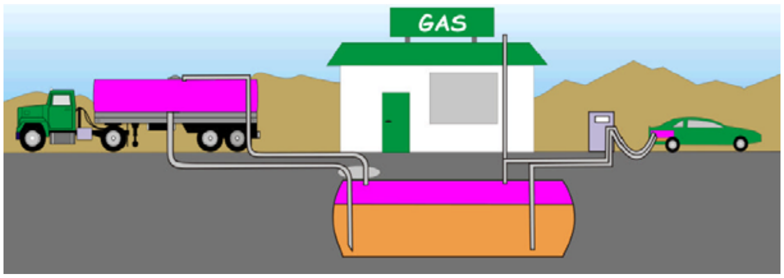
Refueling of underground service station tanks is a major source of evaporative hydrocarbon emissions. VOCs are released as the underground storage tank is refilled, when gasoline vapors in the tank's headspace are displaced. Sources estimate that 10-15 liquid gallons of gasoline are released from vapors displaced from the headspaces of various tanks, each time a gasoline transport truck fully unloads its products (1,2,3). Unless captured through a vapor recovery system, such as Stage I, these emissions will be released directly into the atmosphere.

In many areas, Stage I vapor recovery systems are required to control VOC emissions within the gasoline distribution system, from the refinery to the retail gasoline station. In the Denver metropolitan area, for instance, Stage I is required to control VOC releases that contribute to summertime ozone formation. Fire codes require the use of Stage I at service stations in other areas. But in many places their use is not required, and stations may, or may not, be using any vapor recovery stations, even if they are equipped with them. Stations that are equipped with Stage I vapor recovery systems may not be operating them. Other older stations may not even be equipped with vapor recovery systems.

The following diagram shows how Stage I works. In this diagram the fuel delivery truck unloads its product into the bottom of an underground storage tank through the refueling pipe. A second pipe then draws the vapors being displaced as the underground storage tank is being filling, and discharges them into the now emptying fuel delivery trucks compartment. The empty truck then returns to the refinery or terminal and releases the captured vapors into the refinery's or terminal's vapor recovery system, where they are condensed back into liquid gasoline and reused.

The same illustration also shows how Stage II vapor recovery systems work, by using the same principle, capturing the VOCs produced as an automobile is refueled. As the automobile is refueled, vapors displaced by the car's gasoline tank are drawn back through the dispensing pump back into the underground storage tank by a second refueling tube. There, they either condense into gasoline within the tank, or are directed into the refueling tanker truck, through the station's Stage I system when the underground tank is next refueled by the tank truck.

Stage I Vapor Recovery



Source: Calif. EPA, Nov.18, 2004

References:

"What You Should Know About Vapor Recovery", Michigan Department of Environmental Quality.
"Keeping It Clean: Making Safe and Spill-Free Motor Fuel Deliveries," Petroleum Equipment Institute, December 1992.
"New Hampshire Stage I/II Vapor Recovery Program", New Hampshire Department of Environmental Services.

Air Quality Benefits of Stage One Vapor Recovery
As part of its effort to reduce summertime ozone, the Denver metropolitan area requires the use of Stage 1 at all service stations. It is estimated that because of Stage I requirements, that perhaps 13.2 million pounds of VOCs (18.1 tons per day) are prevented from being emitted into the air*. Air toxics are also reduced.

Stage I vapor recovery systems are efficient. Up to 95%(1) of underground storage-tank refueling vapors are captured. Stage I is also cost effective. Vapors from the underground storage tanks are collected in the now empty tanker truck's compartments and taken back to the refinery or terminal, where they are condensed and reused. At $3.00 a gallon for gasoline seen in the summer of 2007, this equates to $2.1 million dollars worth of gasoline saved annually.

(1), Hensel, John, and Mike Mondloch,"Stage One Vapor Control In Minnesota", Minnesota Pollution Control Agency.

* Based on emission factors from the state of New Hampshire (11 lbs. VOC produced per 1000 gallons of gasoline vapors displaced), and 1.2 billon gallons of gasoline delivered to service stations in the Denver metropolitan area each year.

Cost

Many stations, while not operating their Stage I equipment are equipped with it. Others would have to be retrofitted. The Minnesota Pollution Control Agency estimates that retrofitting a station will cost up to $15,000 per station, with a more typical cost of approximately $10,000 per station. This is a very reasonable cost for the emissions benefits that can be derived.

II: Description of how to implement:
Implementation of Stage I vapor recovery would be through State Implementation Plans. A state could also adopt such as a program as a state-only program if not part of a SIP. The state would enforce the requirements.

III. Feasibility of option:
This option is fairly easy to develop and implement.

IV. Background data and assumptions used
A major assumption is that the four corners area will become nonattainment for summertime ozone, either as a result of elevated measurements, or the implementation of a new, lower, more rigorous ozone standard.

V. Any uncertainty associated with the option (Low, Medium, High):
Low.

VI. Level of agreement within the workgroup for this mitigation option:
Good general agreement.

VII. Cross-over issues to other source groups:
There does not seem to be much cross over.

Mitigation Option: Stage Two Vapor Recovery and Vehicle On-board Refueling Vapor Recovery Systems

<u>I. Description of the mitigation option:</u>
Mandatory use of Stage-II vapor-recover systems as well as programs designed to maintain vehicle's on-board refueling vapor recovery systems reduce evaporative emissions created during automobile refueling.

Automotive refueling is a major source of evaporative hydrocarbon emissions. As a vehicle's gas tank is filled gasoline vapors in the tank's headspace are displaced. It is estimated that when filling an empty 18-gallon fuel tank, 0.06 pounds of VOCs can be released (1,2), if such vapors are not captured by either a service station's Stage II vapor-recovery system, or for newer vehicles, the vehicle's on-board refueling vapor recovery system (this assumes that 30% of the vehicle's gasoline tank's headspace is composed of gasoline vapors and 70% by air) (2).

In a Stage II system, as an automobile is refueled, vapors displaced in the car's gasoline tank are drawn back through the dispensing pump back into the underground storage tank by a second refueling tube. There, they either condense into gasoline within the tank, or are directed into the refueling tanker truck, through the station's Stage I system when the underground tank is next refueled by the tank truck. The following illustration diagrams this.

Stage II Vapor Recovery System

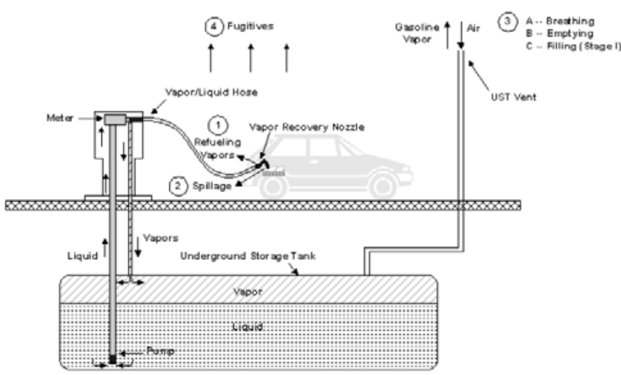
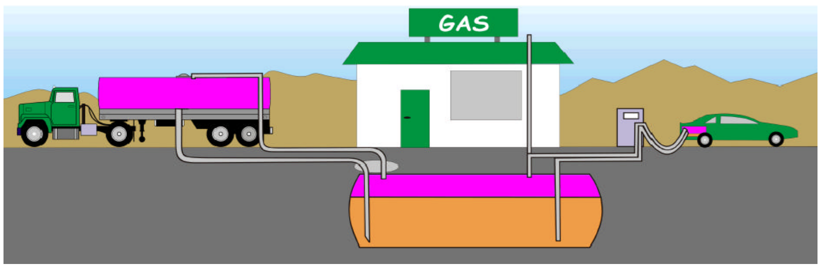


Figure 2. Controlled Stage II Process Operations with vapor recovery system.

Source: "Stage II Vapor Recovery Issue Paper", U.S. EPA, August 12, 2004.
http://www.ct.gov/dep/lib/dep/air/stageII/stage2issuepaper.pdf

Another illustration also shows how Stage II works in conjunction with Stage I. Vapors from the automobile's gasoline tank are routed back into the headspace of the station's underground storage tank. In this diagram the fuel delivery truck unloads its product into the bottom of an underground storage tank through the refueling pipe. A second pipe then draws the vapors being displaced as the underground storage tank is being filling, and discharges them into the now emptying fuel delivery trucks compartment. The empty truck then returns to the refinery or terminal and releases the captured vapors into the refinery's or terminal's vapor recovery system, where they are condensed back into liquid gasoline and reused.

Stage I & II Vapor Recovery Systems



Source: Calif. EPA, Nov. 18, 2004

References:
"New Hampshire Stage I/II Vapor Recovery Program", New Hampshire Department of Environmental Services.
"Stage II Vapor Recovery Issue Paper", U.S. EPA, August 12, 2004.

Air Quality Benefits of Stage II Vapor Recovery Systems

As part of its effort to reduce summertime ozone, many metropolitan areas across the nation with ozone concerns have adopted the use of Stage II vapor recovery systems at service stations. Stage II vapor recovery systems can be efficient. Depending on the frequency of inspection and equipment maintenance, up to 95%(1) of refueling vapors may be captured. In reducing VOCs, many air toxics, such as benzene and 1,3 butadiene are also reduced.

Modeling conducted by Mobiles Sources Program, Air Pollution Control Division, of the Colorado Department of Public Health and Environment, indicate that implementation of a Stage II vapor recovery program in the Denver Metropolitan area would reduce overall mobile source VOCs by 5.5% in the year 2007, and by 3.8% in the year 2012, when more vehicles are equipped with on-board vapor recovery systems.

On-board Refueling Vapor Recovery (ORVR) systems

On-board refueling vapor recovery (ORVR) systems work by routing escaping vapors from the fuel tank; through a charcoal canister that absorbs VOCs. The trapped VOCs are then pulled from the canister into the engine where they are burnt. ORVR systems have become standard equipment on light-duty automobiles beginning in 1998, and light duty trucks (trucks 1-2 starting in 2001, and trucks 3-4 in 2004).

As stated before, as the fleet penetration of on-board refueling vapor recovery systems increases, the emissions benefit from Stage II decreases somewhat. Currently, in the Denver metropolitan area, 54% of all gasoline motor vehicles now are equipped with on-board vapor recovery systems. As more of the fleet is equipped with on-board refueling vapor recovery systems, the effectiveness of Stage II is reduced. However, working together, they will both reduce refueling losses in the near to medium term, as shown in CDPHE's MOBILE6 modeling results. It should be pointed out that as ORVR systems deteriorate, refueling losses increase. At some point in the future, it may be necessary to implement some sort of inspection program to find and have fixed broken ORVR systems, maintaining the air quality benefits of these systems.

The U.S. EPA in their report "Stage II Vapor Recovery Issue Paper (August 12, 2004) includes a diagram (Figure 5, page 16 - shown below), of the refueling emissions trends for a hypothetical State. From inputs contributed by the American Petroleum Institute, this illustration shows four different scenarios; Stage II vapor recovery controls only (the blue line); on-board refueling vapor recovery only (the red line); Stage II vapor recovery controls with on-board refueling vapor recovery, where the ORVR interferes with the Stage II controls (the green line); and 4) Stage II vapor recovery controls and on-board refueling vapor recovery, where the ORVR does not interfere with the Stage II controls (the black line). The chart diagrams the years from 2005 through 2035 (1).

As seen in this diagram, a state with an existing Stage II vapor recovery program with an 85% effectiveness (blue line) will have a fraction of the refueling VOC emissions as a state that does not (the red line) in the year 2005. As more vehicles are equipped with ORVR systems, this advantage decreases, with at some point before 2015, the benefits of both control measures being equal. The blue line increases over time because of the increase in vehicle miles travels and does not include the effect of ORVR. However, before this time (2015), Stage II vapor recovery programs will give large benefits.

The other two scenarios shown represent decreasing VOCs over time with both control measures. There has been some research showing that Stage II can potentially interfere with on-board refueling vapor recovery systems. This is represented by the green line, where there is some increase in emissions as a result. However, all new Stage II systems certified by the state of California must show no interference with the ORVR. Using these approved systems, total VOCs are reduced for both Stage II and ORVR (the black line), where until 2025 there is a noticeable improvement having both systems.

Refueling Emissions Trends for Four Scenerios:

1) Stage II controls only (Blue Line), 2) On-board Refueling Vapor Recovery (ORVR) only (Red Line), 3) Stage II & ORVR with compatibility issues (Green Line), 4) Stage II & ORVR with no compatibility issues (Black Line)

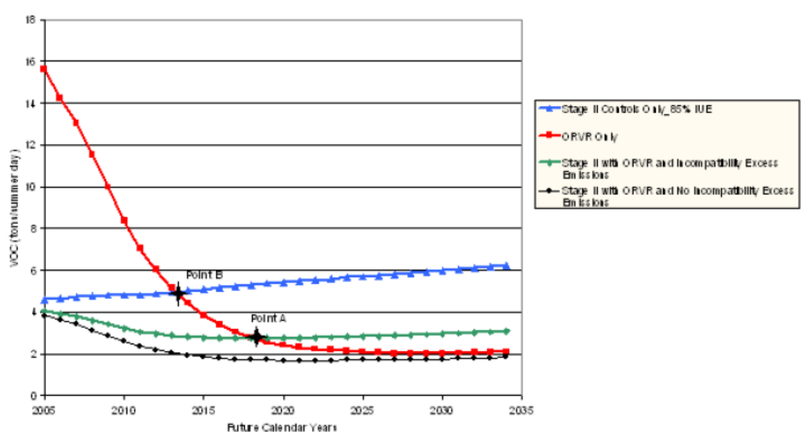


Figure 5. General emissions trends expected for refueling emissions in future calendar years for a hypothetical State (based on API studies).

Source: "Stage II Vapor Recovery Issue Paper", U.S. EPA, August 12, 2004.
http://www.ct.gov/dep/lib/dep/air/stageII/stage2issuepaper.pdf

(1) "Stage II Vapor Recovery Issue Paper", U.S. EPA, August 12, 2004.

Cost

There are costs to retrofit service stations with the necessary plumbing and equipment. In some cases this will be a major renovation to the station. Additionally, there will be on-going costs associated with operating and maintaining the Stage II vapor recovery system and equipment.

The state of New Hampshire, which has an operational Stage II vapor recovery program, estimates that the cost of Stage II installation at between $18,000 and $30,000 per station, depending on the station (1). They estimate on-going annual maintenance costs to be $1000 to $4000 per station yearly (1). Stage II requirements affect any station in that state that sells or has throughput of more than 420,000 gallons of gasoline annually (1).

(1) Environmental Fact Sheet, "New Hampshire's Gasoline Vapor Recovery Program - Protecting the Air We Breathe" New Hampshire Department of Environmental Services, 2004.

II: Description of how to implement:

Implementation of Stage II vapor recovery would be through State Implementation Plans. The state would enforce the requirements.

III. Feasibility of option:

This option is moderately hard to develop and implement. Gasoline service stations that are already plumbed for Stage II, and do not have to tear up concrete to put in vapor recovery plumbing are relatively easy to upgrade. Stations that need extensive work to install will be more difficult. Industry will not be supportive of this option.

IV. Background data and assumptions used

A major assumption is that the four corners area will become nonattainment for summertime ozone, either as a result of elevated measurements, or the implementation of a new, lower, more rigorous ozone standard.

V. Any uncertainty associated with the option (Low, Medium, High):

Low.

VI. Level of agreement within the workgroup for this mitigation option:

Good general agreement.

VII. Cross-over issues to other source groups:

There does not seem to be much cross over.

OTHER SOURCES: PUBLIC COMMENTS

Other Sources Public Comments

Comment	Mitigation Option
Dear Task Force Representative: I work for the Ute Mountain Tribe's Environmental Programs Department. We are about to partner with the EPA and the USGS to monitor radionuclides in the air and water around White Mesa, Utah where there is the only operating uranium mill in the nation. They are increasing production dramatically at the mill. We have significant concerns about radioactive dust blowing around out there. Any assistance that you or your staff could provide, funding if possible, would be a great thing. In the end we will have a publicly available, peer-reviewed report published by USGS and EPA. This could be a very important piece of the 4 corners air quality puzzle for you. My contact information is: Scott Clow, Water Quality Specialist, Ute Mountain Ute Tribe, PO Box 448, Towaoc, CO 81334, (970) 564-5431, scute@fone.net Thanks for considering this. Sincerely, Scott	
The last mitigation option makes me think that it is time to start considering regulating wood and coal burning stoves all-together. We have a tendency in the 4 corners to believe that we are small-fry, but continued urbanization is delivering us many big-city problems. In all, oil, gas and power plants tend to overshadow the cumulative impacts of residential activities. Our county governments should consider mitigation options accordingly.	
It is not enough to address the larger sources of air pollution in the Four Corners area. The efforts of this task force must also address the cumulative effects of the smaller sources.	
This is a great option. The Farmington/Aztec/Bloomfield area is an urban corridor, and the Durango/Bayfield area is quickly becoming so as well. We could easily reduce emissions and highway miles traveled if we were to expand upon park-and-ride systems (I believe I saw an ad for one between Ignacio and Durango) and also municipal transit.	Public Buy-in through Local Organizations to push for transportation alternatives and ordinances
Public outreach is great (often people are unaware of the health problems due to burning), but it may not reach the few and highly resistant people who burn regularly (both commercial and residential). As a resident, I would like to be able to call the sheriff and have enforcement that is effective (a fine, for example).	Develop Public Education and Outreach Campaign for Open Burning
The worst offending vehicles pass because their owners know how to beat the system on testing. Just enforce laws about taking cars off the road that visually are not in compliance. Add a tax based on engine size or exempt smaller engines and low weight vehicles.	Automobile Emissions Inspection Program
IM Programs will only work if all areas in that region are included. If they are not then owners of car will find ways to get around the program. Most of the owners that would do this are the owners of the cars that are the problem. Another way to make sure that your program is effective is to make sure that there is a assistance program for owners that can not afford to get their car emissions fixed.	Automobile Emissions Inspection Program

Comment	Mitigation Option
The IM programs will only be effective for our purposes if they are implemented in all areas. Also, the emissions programs for cars need stricter standards, thus making it economically infeasible to own larger engine, less efficient vehicles. There will always be those who find their way around the laws. However, if those laws are stricter, actually enforced, and applied throughout the Four Corners area then more problem vehicles will be taken off the road.	Automobile Emissions Inspection Program
On a voluntary basis, people could "adopt/subsidize" other vehicles that are not meeting emissions specs. Maybe this adoption could be tax deductible or a tax credit. How do we address the high emitting, newer vehicles (ie large trucks/cars)from the LEV (low emission vehicles)? Maybe a taxing structure would help both reduce the demand for new higher polluting vehicles, and help get high polluting older (the old "beater") vehicles off the road by helping to pay for their improvement/replacement.	Automobile Emissions Inspection Program
I would like City (and County if possible) ordinances to restrict idling. A rule that everyone follows will make it easier to get everyone on board the "no idling" plan. Public outreach also has to follow to teach people why idling causes problems and how "no idling" make make a difference. Signage at parking areas/unloading areas boat ramps, water filling stations/hydrants, the post office, grocery stores and other parking lots and etc. can remind drivers to turn off their engines.	Idle Ordinances
School bus retrofit--Let's do it! Then add public outreach to encourage more students to ride the bus, and we reduce emissions because the parents are not lined up in their cars to pick up/drop off their kids at school.	School Bus Retrofit
Though indirectly related to this topic, homes need to be upgraded weatherized and insulated so that we decrease the amount of fuel needed. Public outreach might help teach people how to build a clean fire. And people are burning trash in their wood stoves (similar to open burning). Coal is often used for heating and is particularly high in emissions, and seems to be equal to open burning.	Subsidy Program for Cleaner Residential Fuels

Energy Efficiency, Renewable Energy and Conservation

Energy Efficiency, Renewable Energy and Conservation: Preface

The Task Force identified a need for an Energy Efficiency, Renewable Energy, and Conservation (EEREC) mitigation option section for the Task Force report. Since this category had cross over among the groups, each group contributed to this section of the report. The Other Sources and Power Plants Work Groups met together at the November 8, 2006 Task Force meeting and briefly at the February 8, 2007 meeting to discuss EEREC as a topic. Louise Martinez, Bureau Chief of Energy Efficiency Programs with the New Mexico Energy, Minerals, and Natural Resources Department, gave a presentation on New Mexico Clean Energy Programs in the work group breakout session. New Mexico has a comprehensive set of renewable energy incentives to attract new projects and developers. The Four Corners area has a very strong solar energy resource and potential for energy efficiency improvements which both could offer environmental and health benefits.

Energy use is increasing in the Four Corners Area and in the U.S. as a whole. New generation will be required to meet additional energy demands. The work group on EEREC discussed that we could use the proactive NM position on clean energy as an example of a model to help write mitigation options for developing clean energy in the 4 Corners. Options focused on not only industry but also consumer behaviors. Three general areas were identified for options. Twenty-one mitigation options were brainstormed for the EEREC section; 18 were drafted.

Efficiency is important because efficiency is getting more out of each bit of energy we use. The result can be a direct benefit by reducing emissions from power plants or other sources and getting work done for less money. Efficiency has an indirect benefit by reducing the demand for additional energy production.

The work group brainstormed and drafted several options relating to efficiency. Options written included the following: Improved efficiency of home & industrial lighting; home audits for energy efficiency, as well as green building and energy efficiency incentives. An option was also written to improve county & city planning efforts. One option on power generation energy efficiency at existing power plants was written and included in the Existing Power Plants mitigation option section.

Renewable energy is important because it can benefit air quality by complementing and offsetting existing fossil fuel energy use and generation with clean energy sources. The work groups wrote options on better utilizing the solar resources in the Four Corners; expanding renewable portfolio standards to the Four Corners area municipalities and power cooperatives; creating/improving net-metering agreements with the electric utilities; and several others. A few policy options were written concerning importing and using only clean energy locally. One option tying together renewable energy and energy efficiency was written on “The Use and Credit of Energy Efficiency and Renewable Energy in the Environmental Permitting Process.” An option discussing the viability of biomass as an energy source to mitigate air pollution was also drafted in addition to an option for a bioenergy center.

Conservation, or using less energy, is also important because it reduces air pollution. Burning fossil fuels directly or using electricity generated by fossil fuel combustion results in increased air pollutants. Decreasing energy consumption correlates to decreased emissions. Options focusing on conservation centered around energy use. Options that could improve conservation efforts and reduce emissions included smart metering, direct load control, time based pricing, and residential bill structure changes. The work group discussed the need for more education of the public & industry on these issues. An option for an “Outreach Campaign for Conservation & Wise Use of Energy” was drafted. The San Juan VISTAS program, a voluntary emissions reduction program emphasizing energy efficiency, was discussed as a possible model for all sectors of industry and the community to work together to improve air quality through cost effective strategies in the Four Corners area.

ENERGY EFFICIENCY

Mitigation Option: Advanced Metering

I. Description of the mitigation option

Overview

Advanced Metering is the integration of electronic communication into metering technology to facilitate two-way communication between the utility and the customer equipment. Increasing electric energy prices and a growing awareness of the need to reduce the environmental impact of electric energy consumption are directing the industry, legislators and regulators to turn to Advanced Metering technologies for solutions. Strategic deployment of Advanced Metering Systems will facilitate or enable sustainable and cost-effective Energy Efficiency (EE) and Demand Response (DR) programs while at the same time providing a platform for cost-reducing innovations in the areas of customer service, reliability, operations and business practices.

Partly due to the time lag between when energy is consumed and when the consumption is billed, and partly because there is no tangible commodity to associate with their monthly electric bill, most end-use customers have a difficult time relating their monthly electric bill with their daily energy use patterns. Consequently, a critical component of effective and sustainable EE and DR programs is the ability to provide energy use information to customers in an understandable, timely and useable manner. An Advanced Metering System with its two-way communication system provides an infrastructure for sending and receiving timely energy use and pricing information and, if desired, load control signals directly to customers and end-use equipment.

Advanced Metering Systems supports both EE and DR programs. The primary objective of EE programs is to reduce the total amount of energy used annually by consumers. (DR focuses on shifting energy use to off peak hours and does not necessarily result in energy conservation). EE programs, therefore, are typically focused on consumer education, the use of more energy efficient equipment and other measures such as building improvements to reduce energy losses and waste.

Environmental Benefits - Advanced metering provides indirect benefit to the environment by providing real-time tools to enable the customer to make informed decisions around energy use and conservation. Energy conservation displaces a portion of electric generation and can lead to lower emissions of carbon dioxide (CO2), nitrogen oxides (NOx), sulfur dioxide (SO2, and particulate matter (PM-10). In addition, reduced operation of generating plants means less water use and a reduction in the amount of natural resources (fossil fuels) being extracted from the earth. It can also help prevent or delay the need for building new power plants or other new energy infrastructure.

Economic- Direct operational benefits may result, including reduced monthly metering read costs; reduced meter read to billing time; reduced costs related to unaccounted for energy, energy diversion and energy theft; and reduced time to restore service following an outage.

Other benefits may include:

Increased customer satisfaction due to real time access to energy use information and other meter data by customer service personnel

Increased customer satisfaction due to the availability of accurate real time outage information and reduced outage times

The ability to apply innovative rate structures

Trade-offs - Capital costs to install Advanced Metering Systems can be more costly than conventional meters. Several years may be required for payback of Advanced Metering Systems.

II. Description of how to implement

Mandatory or Voluntary: Could be either voluntary or mandatory. Utilities have demonstrated that voluntary dynamic pricing programs can generate demand response and energy conservation. However, these programs tend to attract only modest levels of participation, in large part because they are narrowly targeted and passively marketed.

The public utility commission is the most appropriate entity to implement.

A differing opinion comment was received on this option during the Task Force Report Public Comment Period: "Advanced metering for home owners will not work. It will only enrich the electric companies who will use the data to set rates higher when people need the energy. An alternative is rolling blackouts on house ACs like that used in the Houston, TX area." See the public comments received for EEREC in the appendix to this section.

III. Feasibility of the option

A. Technical: Good feasibility. Programs have been applied and demonstrated at utilities across the country. Advanced metering systems are commercially available.

B. Environmental: Medium feasibility. Prices and advanced metering systems can be used to modify customer behavior to use less electricity within individual homes and businesses during peak hours, but metering by itself does not save energy. Instead, metering should be viewed as a technology that enables optimized performance and energy efficiency, and provides the information necessary for customers to make more-informed decisions regarding their energy use.

Should energy conservation take place, air emissions, water and fossil fuel use can be reduced through generation displacement. Additionally, EE and DR programs may allow utilities to hold off adding new generation assets, thereby, improving opportunities for employment of more advanced, demonstrated and cost-effective clean coal and renewable energy technology.

C. Economics: Advanced metering systems must be designed, managed, and maintained to cost-effectively meet site specific needs. Applications analysis must consider both initial costs (i.e. purchase and installation) and on-going operations costs (e.g., data analysis, system maintenance, and resulting corrective actions).

IV. Background data and assumptions used

Gillingham, K., R. Newell, and K. Palmer, The Effectiveness and Cost of Energy Efficiency Programs, Resources Publication, Fall 2004, pgs. 22-25, www.rff.org/Documents

Federal Energy Regulatory Commission, Assessment of Demand Response and Advanced Metering, Staff Report, Dockett No. AD-06-2-000

Assumption: Regulatory rate structures that allow for decoupling profits from sales to remove disincentives to conservation.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium. Voluntary programs do not guarantee energy conservation and emissions reductions.

VI. Level of agreement within the work group for this mitigation option

Good. This option write-up stems from a discussion at the February 7, 2007 meeting of the Power Plant Working Group.

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

Other Sources Group- Renewable Energy, Energy Efficiency and Conservation Mitigation Options

Mitigation Option: Cogeneration/Combined Heat and Power

I. Description of the mitigation option

Combined Heat and Power (CHP) is the sequential or simultaneous generation of multiple forms of useful energy (usually mechanical and thermal) in a single, integrated system. CHP systems consist of a number of individual components – prime mover (heat engine), generator, heat recovery, and electrical interconnection – configured into an integrated whole. The type of equipment that drives the overall system (i.e., the prime mover) typically identifies the CHP system. Prime movers presented the CHP systems discussed herein include reciprocating engines, combustion or gas turbines, steam turbines, and microturbines.

These prime movers are capable of burning a variety of fuels, including natural gas, coal, oil, and alternative fuels to produce shaft power or mechanical energy. Although mechanical energy from the prime mover is most often used to drive a generator to produce electricity, it can also be used to drive rotating equipment such as compressors, pumps, and fans. Thermal energy from the system can be used in direct process applications or indirectly to produce steam, hot water, hot air for drying, or chilled water for process cooling. When considering both thermal and electrical processes together, CHP typically requires only ¾ the primary energy separate heat and power systems require. This reduced primary fuel consumption is key to the environmental benefits of CHP, since burning the same fuel more efficiently means fewer emissions for the same level of output.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of CHP should be "voluntary" since the economics, operational aspects and emissions must be customized to the design objectives of the facility.
B. Indicate the most appropriate agency(ies) to implement**:** Since the option is voluntary and based upon the business decision of the entity proposing the facility, there is agency that would be in a position to mandate requiring CHP to be used. However, there could be a number of state agencies involved in permitting a CHP facility, including the state Air Quality Division, to issue air quality related construction and operating permits as appropriate.

III. Feasibility of the option

A. CHP Technologies

1. Gas turbines: are typically available in sizes ranging from 500 kW to 250 MW and can operate on a variety of fuels such as natural gas. Most gas turbines typically operate on gaseous fuel with liquid fuel as a back up. Gas turbines can be used in a variety of configurations including (1) simple cycle operation with a single gas turbine producing power only, (2) combined heat and power (CHP) operation with a single gas turbine coupled and a heat recovery exchanger and (3) combined cycle operation in which high pressure steam is generated from recovered exhaust heat and used to produce additional power using a steam turbine. Some combined cycles systems extract steam at an intermediate pressure for use and are combined cycle CHP systems. Many industrial and institutional facilities have successfully used gas turbines in CHP mode to generate power and thermal energy on-site. Gas turbines are well suited for CHP because their high-temperature exhaust can be used to generate process steam. Much of the gas turbine-based CHP capacity currently existing in the United States consists of large combined-cycle CHP systems that maximize power production for sale to the grid.

2. Microturbines, which are small electricity generators that can burn a wide variety of fuels including natural gas, sour gases (high sulfur, low Btu content), and liquid fuels such as gasoline, kerosene, and diesel fuel/distillate heating oil. Microturbines use the fuel to create high-speed rotation that turns an electrical generator to produce electricity. In CHP operation, a heat exchanger referred to as the exhaust gas heat exchanger, transfers thermal energy from the

microturbine exhaust to a hot water system. Exhaust heat can be used for a number of different applications including potable water heating, absorption chillers and desiccant dehumidification equipment, space heating, process heating, and other building uses. Microturbines entered field-testing in 1997 and the first units began commercial service in 2000. Available and models under development typically range in sizes from 30 kW to 350 kW.

3. There are various types of reciprocating engines that can be used in CHP applications. Spark ignition (SI) and compression ignition (CI) are the most common types of reciprocating engines used in CHP-related projects. SI engines use spark plugs with a high-intensity spark of timed duration to ignite a compressed fuel-air mixture within the cylinder. SI engines are available in sizes up to 5 MW. Natural gas is the preferred fuel in electric generation and CHP applications of SI. Diesel engines, also called CI engines, are among the most efficient simple-cycle power generation options in the market. These engines operate on diesel fuel or heavy oil. Dual fuel engines, which are diesel compression ignition engines predominantly fueled by natural gas with a small amount of diesel pilot fuel, are also used. Higher speed diesel engines (1,200 rpm) are available up to 4 MW in size, while lower speed diesel engines (60 - 275 rpm) can be as large as 65 MW. Reciprocating engines start quickly, follow load well, have good part-load efficiencies, and generally have high reliabilities. In many instances, multiple reciprocating engine units can be used to enhance plant capacity and availability. Reciprocating engines are well suited for applications that require hot water or low-pressure steam.

4. Steam turbines that generate electricity from the heat (steam) produced in a boiler for CHP application. The energy produced in the boiler is transferred to the turbine through high-pressure steam that in turn powers the turbine and generator. This separation of functions enables steam turbines to operate with a variety of fuels including natural gas. The capacity of commercially available steam turbine typically ranges between 50 kW to over 250 MW. Although steam turbines are competitively priced compared to other prime movers, the costs of a complete boiler/steam turbine CHP system is relatively high on a per kW basis. This is because steam turbines are typically sized with low power to heat (P/H) ratios, and have high capital costs associated with the fuel and steam handling systems and the custom nature of most installations. Thus the ideal applications of steam turbine-based CHP systems include medium- and large-scale industrial or institutional facilities with high thermal loads and where solid or waste fuels are readily available for boiler use.

B. Environmental: CHP technologies offer significantly lower emissions rates per unit of energy generated compared to separate heat and power systems. The primary pollutants from gas turbines are oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOCs) (unburned, non-methane hydrocarbons). Other pollutants such as oxides of sulfur (SO_x) and particulate matter (PM) are primarily dependent on the fuel used. Similarly emissions of carbon dioxide are also dependent on the fuel used. Many gas turbines burning gaseous fuels (mainly natural gas) feature lean premixed burners (also called dry low-NO_x burners) that produce NO_x emissions ranging between 0.3 lbs/MWh to 2.5 lbs/MWh with no post combustion emissions control. Typically commercially available gas turbines have CO emissions rates ranging between 0.4 lbs/MWh – 0.9 lbs/MWh. Selective catalytic reduction (SCR) or catalytic combustion can further help to reduce NO_x emissions by 80 percent to 90 percent from the gas turbine exhaust and carbon-monoxide oxidation catalysts can help to reduce CO by approximately 90 percent. Many gas turbines sited in locales with stringent emission regulations use SCR after-treatment to achieve extremely low NO_x emissions.

Microturbines have the potential for low emissions. All microturbines operating on gaseous fuels feature lean premixed (dry low NO_x, or DLN) combustor technology. The primary pollutants from microturbines include NO_x, CO, and unburned hydrocarbons. They also produce a negligible amount of SO_2.

Microturbines are designed to achieve low emissions at full load and emissions are often higher when operating at part load. Typical NO_x emissions for microturbine systems range between 0.5 lbs/MWh and 0.8 lbs/MWh. Additional NO_x emissions removal from catalytic combustion is microturbines is unlikely to be pursued in the near term because of the dry low NO_x technology and the low turbine inlet temperature. CO emissions rates for microturbines typically range between 0.3 lbs/MWh and 1.5 lbs/MWh.

Exhaust emissions are the primary environmental concern with reciprocating engines. The primary pollutants from reciprocating engines are NO_x, CO, and VOCs. Other pollutants such as SO_x and PM are primarily dependent on the fuel used. The sulfur content of the fuel determines emissions of sulfur compounds, primarily SO_2. NO_x emissions from reciprocating engines typically range between 1.5 lbs/MWh to 44 lbs/MWh without any exhaust treatment. Use of an oxidation catalyst or a three way conversion process (non-selective catalytic reductions) could help to lower the emissions of NO_x, CO and VOCs by 80 percent to 90 percent. Lean burn engines also achieve lower emissions rates than rich burn engines.

Emissions from steam turbines depend on the fuel used in the boiler or other steam sources, boiler furnace combustion section design, operation, and exhaust cleanup systems. Boiler emissions include NO_x, SO_x, PM, and CO. The emissions rates in steam turbine depend largely on the type of fuel used in the boiler. Typical boiler emissions rates for NO_x with any postcombustion treatment range between 0.2 lbs/MWh and 1.24 lbs/mmBtu for coal, 0.22 lbs/mmBtu to 0.49 lbs/mmBtu for wood, 0.15 lbs/mmBtu to 0.37 lbs/mmBtu for fuel oil, and 0.03lbs/mmBtu – 0.28 lbs/mmBtu for natural gas. Uncontrolled CO emissions rates range between 0.02 lbs/mmBtu to 0.7 lbs/mmBtu for coal, approximately 0.06 lbs/mmBtu for wood, 0.03 lbs/mmBtu for fuel oil and 0.08 lbs/mmBtu for natural gas. A variety of commercially available combustion and post-combustion NO_x reduction techniques exist with selective catalytic reductions achieving reductions as high as 90 percent. SO_2 emissions from steam turbine depend largely on the sulfur content of the fuel used in the combustion process. SO_2 composes about 95% of the emitted sulfur and the remaining 5 percent are emitted as sulfur tri-oxide (SO_3). Flue gas desulphurization (FGD) is the most commonly used post-combustion SO_2 removal technology and is applicable to a broad range of different uses. FGD can provide up to 95 percent SO_2 removal.

While not considered a pollutant in the ordinary sense of directly affecting health, CO_2 emissions do result from the use the fossil fuel based CHP technologies. The amount of CO2 emitted in any of the CHP technologies discussed above depends on the fuel carbon content and the system efficiency. The fuel carbon content of natural gas is 34 lbs carbon/mmBtu; oil is 48 lbs of carbon/mmBtu and ash-free coal is 66 lbs of carbon/mmBtu.

<u>C. Economic:</u> The total plant cost or installed cost for most CHP technologies consists of the total equipment cost plus installation labor and materials, engineering, project management, and financial carrying costs during the construction period. The cost of the basic technology package plus the costs for added systems needed for the particular application comprise the total equipment cost. Total installed costs for gas turbines, microturbines, reciprocating engines, and steam turbines are comparable. The total installed cost for typical gas turbines ranges from \$785/kW to \$1,780/kW while total installed costs for typical microturbines in grid-interconnected CHP applications may range anywhere from \$1,339/kW to \$2,516/kW. Commercially available natural gas spark-ignited engine gensets have total installed costs of \$920/kW to \$1,515/kW, and steam turbines have total installed costs ranging from \$349/kW to \$918/kW.

Non-fuel operation and maintenance (O&M) costs typically include routine inspections, scheduled overhauls, preventive maintenance, and operating labor. O&M costs are comparable for gas turbines, gas engine gensets, steam turbines and fuel cells, and only a fraction higher for microturbines. Total O&M costs range from \$4.2/MWh to \$9.6/MWh for typical gas turbines, from \$9.3/MWh to \$18.4/MWh for commercially available gas engine gensets and are typically less than $4/MWh for steam turbines. Based on manufacturers offer service contracts for specialized maintenance, the O&M costs for microturbines appear to be around $10/MWh.

IV. Background data and assumptions used

A. CHP offers energy and environmental benefits over electric-only and thermal-only systems in both central and distributed power generation applications. CHP systems have the potential for a wide range of applications and the higher efficiencies result in lower emissions than separate heat and power generation system. The advantages of CHP broadly include the following:

- The simultaneous production of useful thermal and electrical energy in CHP systems lead to increased fuel efficiency.
- CHP units can be strategically located at the point of energy use. Such onsite generation avoids the transmission and distribution losses associated with electricity purchased via the grid from central stations.
- CHP is versatile and can be coupled with existing and planned technologies for many different applications in the industrial, commercial, and residential sectors.

V. Any uncertainty associated with the option Medium

VI. Level of agreement within the work group for this mitigation option

Although a general discussion of this option has not occurred between the working group members, most of the members do not have technical experience working with CHP facilities.

Source of Information: Catalogue of CHP Technologies, U.S. Environmental Protection Agency, Combined Heat and Power Partnership

Mitigation Option: Green Building Incentives

I. Description of the mitigation option

This option involves the promotion of the Leadership in Energy Efficiency and Design certification LEED through state sponsored incentives. The LEED Green Building Rating System™ is the nationally accepted benchmark for the design, construction, and operation of high performance green buildings. LEED gives building owners and operators the tools they need to have an immediate and measurable impact on their buildings' performance. LEED promotes a whole-building approach to sustainability by recognizing performance in five key areas of human and environmental health: sustainable site development, water savings, energy efficiency, materials selection, and indoor environmental quality.

The cost of LEED certification depends upon: the level of certification sought, the particular project demographics and characteristics, the availability of grants for achieving certification, the LEED experience of the Design Team, the LEED experience of the estimator, the stage in the design at which the Client makes the decision to seek certification (the earlier the better), and the Client's perception of the value and benefits of a more attractive building environment for their occupants. While the factors above may seem numerous, they are quantifiable, they can be priced, and they can be managed.

Certain aspects are realized at no additional cost due to the high level construction performance that today's contractors insist upon as standard practice. Clearly, the higher the certification level, the more it is required to accept the points that have significant additional cost impact. The strategy therefore is to firstly seek the points that have no financial impact, followed by either the insignificant premium costs or the insignificant additional costs. The expensive points are usually only sought when applying for Gold or Platinum certification.

II. Description of how to implement

A. Mandatory or voluntary: Because of concerns associated with the additional costs of certification, this program should be voluntary in scope. Yet, it should be mandatory for all new government buildings to be modeled after some of the options and foundations that this program is built upon, without necessarily reaching for LEED certification.

B. Indicate the most appropriate agency(ies) to implement: Colorado/NM Offices of Energy Management and Conservations,

III. Feasibility of the option

A. Technical: There are only two buildings with the highest LEED certification nation wide, although this certification is technically feasible. There are thousands of buildings build or retrofitted throughout the nation that initially use the guidelines and practices laid out in the LEED certification although they are not LEED certified.

B. Environmental: The environmental benefits of energy efficiency programs are very well documented.

C. Economic: This certification does increase the cost of construction through additional project management and supply demands. Although there are additional costs, the LEED certification does show economic benefits over the life of the building.

IV. Background data and assumptions used

V. Any uncertainty associated with the option: Medium

VI. Level of agreement within the Work Group for this option: TBD

Mitigation Option: Improved Efficiency of Home and Industrial Lighting

I. Description of the Mitigation Option

Utilizing compact fluorescent lights can result in significant energy savings when compared to traditional incandescent lights. Improved lighting efficiency in homes and in commercial/industrial business applications throughout the Four Corners States has tremendous potential to reduce energy consumption, save money, and reduce the amount of fuel burned in coal fired power plants. Burning less coal would result in fewer air pollution emissions.

One quote commonly used in news articles states "If every home in the U.S. switched one light bulb with an ENERGY STAR, we would save enough energy to light more than 2.5 million homes for a year and prevent greenhouse gases equivalent to the emissions of nearly 800,000 cars" (U.S. EPA, 2006).

Background:
Artificial lighting accounts for approximately 15 percent of the energy use in the average American home (U.S. DOE, 2006). Lighting consumes about 20 percent of all electricity used in the U.S. The nationwide lighting figure is potentially as high as 21-34 percent when the air conditioning needed to offset the heat produced by conventional lighting is considered (Rocky Mountain Institute, 2006).

Benefits: Energy Star qualified compact fluorescent light bulbs (CFLs) have many benefits including:

CFLs use 70 to 75 percent less energy than standard light bulbs (General Electric Company, 2006) with minimal loss of function. If the cost of the bulbs, lower energy use, and longer operating life are considered, a consumer can save approximately $52 over eight years for each CFL bulb that replaces a standard light bulb (Rocky Mountain Institute, 2004).

More than 90 percent of the energy used by incandescent lights is given off as heat, which creates the need run air conditioners to compensate for the heat generation and increases energy use (Rocky Mountain Institute, 2006). CFLs generate 70 percent less heat, reducing the need to cool interior air (US EPA, 2006).

CFLs commonly have an operating life of 6,000-15,000 hours compared to 750-1,500 hours for the average incandescent light (USDOE, 2006). CFLs last from 6-15 times longer.

At 4 mg of mercury per light, CFLs have the lowest mercury content of all lights containing mercury. All fluorescent lights contain mercury, incandescent lights do not. Use of CFLs results in a net reduction in mercury because coal power is such a large source of atmospheric mercury. The 70 percent lower energy consumption from CFLs compared to incandescent lights, results in a 36 percent mercury reduction into the atmosphere by coal-burning power plants. With proper recycling, the mercury released by CFLs decreases up to 76 percent compared to incandescent lights (US EPA, 2002; Rocky Mountain Institute, 2004).

Reduction in coal produced energy consumption would also result in a decrease of SOx, NOx, CO2, and other air pollution emissions. It can be demonstrated that running a 100-watt light bulb 24 hours a day for one year requires about 714 pounds of coal burned in a coal power generator. CFLs that use 70 to 75 percent less energy, would also translate from less power used, less coal burned, and fewer emissions. "Every CFL can prevent more than 450 pounds of emissions from a power plant over its lifetime" (U.S. EPA, 2006)

II. Description of how to implement

It has been determined that lack of awareness about the environmental benefits and energy/cost savings of CFL lights is the single largest barrier to their widespread use. CFL light replacement and education programs already exist in the U.S. and in other countries. Components of these programs were used in preparing this mitigation option.

Options could include any or all of the following:

States adopt the goal of delivering one free CFL bulb to every household in Colorado, New Mexico, Arizona, and Utah. Utilities, businesses, communities, and volunteers work together to deliver bulbs and information on the cost savings and environmental benefit of using CFLs.
Within the Four Corners States, adopt a campaign which includes regional advertising, information brochures, and marketing to promote awareness about the energy efficiency and environmental benefits of switching to CFL lights.
Provide light retailers with point-of-sale displays illustrating CFL cost savings, energy savings, proper CFL bulb selection, environmental benefits etc.
Offer State tax incentives for businesses/corporations that build or retrofit facilities using advanced lighting technologies including CFLs.

Voluntary or mandatory – The responsibility to develop a CFL light distribution and education program should be headed by the State governments of the Four Corners region. Coal power plants, utility companies, and other energy-related industry could voluntarily contribute to the purchase of CFL lights for distribution in households, and also contribute to educational awareness programs.

B. Indicate the most appropriate agency(ies) to implement – Colorado Department of Public Health and the Environment, New Mexico Environment Department, Utah Division of Air Quality, Arizona Department of Environmental Quality, DOE and EPA should take lead program roles. Certain aspects, such as purchasing lights for distribution, could be cooperatively funded by the Four Corners region coal-burning power plants, or State governments.

III. Feasibility of the Option

Technical: CFL technology is well developed and commonly available. In fact, large manufacturers of CFLs such as the General Electric Company and large distributors such as Walmart have embarked on major campaigns to promote and distribute CFL lights primarily for the "green" energy savings they represent (Fishman, 2006).

Environmental: Proven 70 percent reduction in energy consumption compared to traditional incandescent lights. Energy efficiency translates to reduction in air pollution emissions from coal-fired power plants. Lowest mercury content of all fluorescent lights, lower overall mercury emissions due to less coal based energy consumed.

Economic: Proven cost savings to consumers due to high energy efficiency and longer bulb life. If a 75 watt bulb is replaced by an 18 watt CFL bulb which is operated four hours a day, the estimated eight year savings is $36 - $52 (U.S. EPA, 2006, Rocky Mountain Institute, 2004). This calculation accounts for the higher purchase cost of CFLs.

IV. Background Data and Assumptions Used

(1) Fishman, Charles, 2006. How Many Lightbulbs Does it Take to Change the World? One. And You're Looking at It. Fast Company Magazine, New York, NY.
www.fastcompany.com/magazine/108/open_lightbulbs.html

(2) General Electric Company, 2006. Ecomagination – For the Home: Compact Fluorescent Lighting. http://ge.ecomagination.com

(3) U.S. DOE, 2006. Energy Efficiency and Renewable Energy Consumers Guide: Lighting. http://www.eere.energy.gov/consumer/your_home/lighting

(4) U.S. EPA, 2006. Compact Fluorescent Light Bulbs: ENERGY STAR. Http://www.energystar.gov/

(5) U.S. EPA, 2002. Fact Sheet: Mercury in Compact Fluorescent Lamps (CFLs). www.nema.org/lamprecycle/epafactsheet-cfl.pdf

(6) Rocky Mountain Institute, 2006. Efficient Commercial/Industrial Lighting. http://www.rmi.org/sitepages/pid297.php

(7) Rocky Mountain Institute, 2004. Home Energy Briefs, #2 Lighting. http://www.rmi.org/

V. Any Uncertainty Associated With the Option

Low – both for feasibility and energy savings and environmental benefit through emissions reductions.

VI. Level of Agreement within the Work Group for this Mitigation Option TBD.

VII. Cross-over Issues to the Other Source Groups None at this time.

Mitigation Option: Volunteer Home Audits for Energy Efficiency

I. Description of the mitigation option
This option involves the development and implementation of a program or project that will engage community members in providing free energy audits to area residents. These audits of low income areas will find the largest sources of energy loss in homes and businesses and will provide simple solutions to the problem. Many local programs exist as examples, but currently only one program exists. Farmington had "make a difference day" at college, where they went to 10 homes with weatherization checklist. This could serve as a launching step for the program.

The air quality benefits to the region will be generated by increasing the energy efficiency of the homes and businesses involved in the program, therefore decreasing the amount of energy needed to be created by local coal burning power plants. In addition, those involved in the program can find out other sources by which to reduce their energy consumption (e.g. car pooling, appliance efficiencies).

II. Description of how to implement
A. Mandatory or voluntary: The audit of a home should be made mandatory for any individual or family receiving energy assistance from state or local governments and/or utilities. For those not receiving assistance, the program is voluntary in scope.

Weatherization and insulation subsidization: PNM has a good neighbor program; grants could go to non-profits; rebates could be used.

B. Indicate the most appropriate agency(ies) to implement: Colorado/NM Offices of Energy Management and Conservations, Americorps or Vista programs

III. Feasibility of the option
A. Technical: Similar programs are prevalent nationwide, this option is technically feasible.
B. Environmental: The environmental benefits of energy efficiency programs are documented.
C. Economic: Most energy efficiency programs, especially implemented with volunteers, are economically viable and sustainable.

IV. Background data and assumptions used N/A.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the Work Group for this option All agreed.

VII. Cross-over issues to the other source groups None at this time.

Mitigation Option: The Use and Credit of Energy Efficiency and Renewable Energy in the Environmental Permitting Process

I. <u>Description of the mitigation option</u>

In principle, facilities implementing activities that lead to energy efficiency (EE) and rely upon renewable energy (RE) can receive additional incentives/ flexibility in their State air quality permits. A goal would be to provide alternatives to conventional energy sources that occur within the nexus of environmental, energy, and economic activities. Such an effort would also allow EE/RE to compete with traditional pollution control technologies to reduce emissions and encourage more environmentally-sensitive energy generation.

The benefits to industry might include: categorical permit exemptions for specific source categories that incorporate EE and/or RE if their use result in significant ambient air quality improvements; use of EE/RE to represent offsets for the purpose of major source NSR review; education and promotion of EE/RE for the purpose of avoiding a permit requirement (i.e., reducing emissions below de minimus regulatory thresholds or "syn minoring"); incorporating EE/RE as a control option in the Reasonable Available Control Technology (RACT) review process for minor sources located in non-attainment and attainment/maintenance areas, and; other benefits as identified. State air quality agencies could also provide benefits to industry by considering: "fast tracking" environmental permit requests of facilities incorporating EE/RE; recognizing participating facilities through various environmental leadership awards' programs; and, and other ideas as appropriate.

The benefits to the states could include: air quality improvements and help in avoiding future air quality problems; energy security; economic development (e.g., new jobs); environmental and energy leadership; facilitated collaboration between State and Federal agencies; and synergism of technical resources.

Such EE/RE approaches could be "codified" in State Implementation Plans, Supplemental Environmental Projects, and/or enforceable air pollution permits. EE/RE could also be tied to State Portfolio Standards (e.g., Colorado Renewable Energy Standards at 10% by year 2015) or other mechanisms.

II. <u>Description of how to implement</u>

A. <u>Mandatory or voluntary:</u> Voluntary for industry to enter into EE/RE agreements, though possibly enforceable through State permits or SIPs.

B. B. <u>Indicate the most appropriate agency(ies) to implement:</u> State Air Quality agencies or other authorities responsible for issuing air quality permits; State Offices' of Energy Management and Conservation (or like agencies); Department of Energy, if necessary in determining appropriate EE/RE initiatives;

<u>III. Feasibility of the option</u>

A. <u>Technical:</u> Technically, permitting agencies and interested industry would need to come up with a mutually satisfying definition of "EE/RE," including possibly setting minimum EE/RE requirements. For example, EE/RE efforts might include: establishing/ continuing "green" programs such purchasing wind power to generate a significant percentage of energy to operate office buildings and facilities; incorporating solar power; expanding the use of alternative vehicles as vehicles of first choice in industry fleets; using biodiesel fuel use in fleet vehicles; encouraging other industry partners to adopt green programs and assist them with expertise and experience (peer to peer mentoring); using industry and State resources, combined with other resources, to educate employees and general public to EE/RE measures; and, exploring grants and other funding mechanisms for EE/RE efforts. Also, it would make sense to start this on a pilot level scale to resolve any challenges that are identified in an initial effort.

B. Environmental: It's been demonstrated that there are direct environmental benefits from the use of EE and RE (e.g., reduced emissions of criteria and hazardous air pollutants, including SOx, NOx, mercury, etc.). Such EE/RE may also address concerns for impacts on regional haze and climate change.

C. Economic: EE/RE could be a significant financial gain for participating facilities in terms of: saved revenue from energy efficiency ("profits" could be re-directed to other aspects of the facility/industry); saved revenue by not having to transport fuels across the country, such as coal and heating oil; fuel price protection; reduced exposure to potential carbon taxation; an offset/trading value for early adopters and efficient reducers; public perception, and/or; others to be identified.

IV. Background data and assumptions used

Efforts would need to begin by establishing a workgroup with appropriate professionals who could illuminate opportunities to implement EE/RE through permitting and rule changes. Also, this initiative would need to work with permitting agencies' inventory groups to collect data to identify source categories that may be appropriate pilot project candidates for an EE/RE initiative.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium, as there are not many examples to draw upon. Also, mutually satisfying definitions of EE/RE would need to be developed.

VI. Level of agreement within the work group for this mitigation option.

TBD but is assumed to be medium to high, depending on the workload necessary to get this effort underway.

VII. Cross-over issues to the other source groups TBD

RENEWABLE ENERGY

Mitigation Option: Expand the Renewable Portfolio Standards (RPS) to be Mandatory for Coops and Municipalities

I. Description of the mitigation option

The installation of new renewable generation has the potential to reduce the quantity of fuel combusted at existing fossil generation facilities thereby reducing air emissions and may potentially reduce the size of new generation that is needed to be built in the future.

Investor owned electric utility companies in New Mexico are required to provide 5% of the total energy supplied to its retail customers via renewable energy beginning in January of 2006. This requirement grows by 1% per year until 2011 when the requirement is l0%. This Renewable Portfolio Standard (RPS) requirement is part of the Rule 572 which was adopted by the NM Public Regulation Commission (NMPRC) in December of 2002. The New Mexico State legislature later passed the Renewable Energy Act, signed by the Governor on May 19, 2004, which codified this rule.

II. Description of how to implement

A. Mandatory or voluntary

The Renewable Energy Act states that the NMPRC may require that a rural electric cooperative 1) offer its retail customers a voluntary program for purchasing renewable energy under rates and terms that are approved by the NMPRC, but only to the extent that the cooperative's suppliers make renewable energy available under wholesale power contracts; and 2) report to the NMPRC the demand for renewable energy pursuant to a voluntary program. The Act is silent regarding municipalities at this time.

B. Indicate the most appropriate agency(ies) to implement

The NMPRC, the New Mexico Environment Dept, the New Mexico Energy, Minerals and Natural Resources Dept.

III. Feasibility of the option

A. Technical: Resource maps indicate that there is a good solar resource in the Four Corners area; however, wind energy, biomass, and geothermal are somewhat limited. Solar power generation is still more expensive than fossil-fired generation at this time.

B. Environmental: The environmental benefits of off-setting fossil-fired generation with renewable generation are well documented.

C. Economic: Each individual utility must balance it own unique needs to maintain a balance between reliability, environmental performance and cost. Integrating renewables into a utilities generation portfolio can cause electric prices to increase and adversely affect reliability to the utility's customers.

IV. Background data and assumptions used

Economic Outlook for Various Generation Technologies (2010)				
	Efficiency (%)	Capacity Factor (%)	Overnight Capital Cost(1) ($/kW)	Cost of Electricity (COE)(1) ($/MWh)
Wind (Class 3 to Class 6)(9)	N/A	30-42	1190	53-69

Solar Thermal (Parabolic Trough)	N/A	33	3410	180
Biomass CFB	28	85	2160	67
Coal(2) PC SC	39	80	1350	44
Coal(2) PC USC w/ CO2 capture	30	80	2270	72
Coal(2) CFB	36	80	1480	53
IGCC(2) GE – Quench W/O CO2 capture	37	80	1490	51
IGCC(2) GE – Quench w/ CO2 capture	30	80	1920	65
NGCC(4) (@ $4/MM Btu)	46	80(5)	500	43
NGCC(4) (@ $6/MM Btu)	46	80(5)	500	59
NGCC(4) (@ $8/MM Btu)	46	80(5)s	500	76

Acronyms: kW- kilowatts; MWh – megawatts/hour; CFB- circulating fluidized bed; PC- pulverized coal; SC-supercritical; USC- ultra-supercritical coal; IGCC- integrated gasification combined cycle; CFB- coal-fired boiler; NGCC- natural gas combined cycle

Notes:
All costs in 2006$; COE in levelized constant 2006$ and includes capital cost. Capital Cost is overnight, W/O Owner, AFUDC costs.
All fossil units about 600 MW capacity; Pittsburgh#8 coal for PC, CFB, IGCC.
Based on Gas Turbine technology limitations to handle hydrogen
NGCC unit based on GE 7F machine or equivalent by other vendors;
Represents technology capability
Value shown is 10% emission of total. The remainder is assumed to be absorbed by the biomass plant crop growth cycle
Includes reservoir development and associated cost for fuel supply
Reinjection of fluid in closed loop operation assumed
Wind COE values estimated via 2005 EPRI TAG analysis.

V. Any uncertainty associated with the option (Low, Medium, High)
High. Generally, the co-ops and municipalities do not like mandates.

VI. Level of agreement within the work group for this mitigation option
Mixed due to the fact that municipalities and rural electric cooperatives in the Four Corners area are relatively small and any participation in a statewide RPS will have a minimal impact on air quality.

VII. Cross-over issues to the other Task Force work groups None identified.

Mitigation Option: Four Corners States Adopt California Standards for Purchase of Clean Imported Energy

I. Description of the mitigation option

California has adopted a law that bans import of power from sources that generate more greenhouse gases than in-state natural gas plants. This law, which goes into effect January 1, 2007, impacts power generated in coal-fired plants in the Four Corners area, among others. Critics of this law say it will not accomplish its purpose of reducing emission of greenhouse gases, particularly carbon dioxide, because power from plants that do not meet CA's standards will simply be sold in other markets. If the Four Corners states (CO, NM, UT and AZ) adopted similar rules, pressure would be placed on the owners of many, if not all, the dirty plants in our area, plus a number of others, to clean up their emissions to meet the new standards. In so doing, a real contribution to the reduction of greenhouse gases, as well as other pollutants, would be made.

II. Description of how to implement

Four points relative to the CA legislation need to be addressed.

First, to be effective in a timely way, the rules need to apply to a utility's existing contracts that extend beyond a reasonable period of time, for example, five years. In anticipation of the January 1 implementation date for the CA law, some CA cities are renegotiating their long-term contracts, and extending them out to 2044. This must be avoided. Incentives will have to be provided to both sides in order to entice them to renegotiate their contracts

Second, some of the motivation for contract renegotiation relates to significant reductions in cost of power after the capital costs of the plant are retired. Incentives for renegotiation for similar reasons must be reduced or eliminated.

Third, state laws in the Four Corners area must specify power imported from 'other jurisdictions', such as from tribal nations as well as other states, in order to be effective in our area, since most present and future coal-fired power plants will be built on tribal lands, albeit within one of the Four Corners states. Additionally, tribal jurisdictions may wish to adopt similar legislation on the importation of power into their lands from external sources.

Fourth, the Four Corners states may not have a standard comparable to CA's standard, i.e., that of the greenhouse gas emissions of 'in-state natural gas plants'. In lieu of an appropriate in-state standard, a state could adopt CA's standard, or the average emission level for natural gas fired plants on a national level.

These requirements must be mandatory if they are to be effective

State and tribal permitting agencies should be given responsibility of implementation

III. Feasibility of the option

Technical - Four Corners states can seek technical assistance from the state of CA, which should be willing to assist in order to avoid dilution of the impact of their own law. Monitors of greenhouse gas emissions will need to be in place if not already in use

Environmental – This option would have a significant environmental impact

Economic – This option would also have a significant economic impact. There is no doubt that plants requiring significant pollution upgrades or even plant phase outs would raise the cost to shareholders and that these costs would be passed along to the customer. However, this is appropriate. End runs around the legislation, such as, marketing the power outside CA and the Four Corners area would occur to some extent. Obviously, addressing this issue at a national level would be far superior to a state-by-state approach; however, in lieu of national action, this option takes CA's step significant further.

Political – this option will be a very hard sell. Constituents in all Four States include citizens, including tribal members, with financial interests in status quo.

Legal – Since the U.S. Constitution gives Congress the power to regulate inter-state commerce, CA's law may not hold up to judicial scrutiny. If it doesn't, then this option would be withdrawn.

<u>IV. Background data and assumptions</u>

This option assumes legality, constitutionality and permanence of the CA law. This option would be withdrawn if the Supreme Court gives the EPA the power to regulate greenhouse gases in the case heard November 29 and if the EPA then takes a stance at least as tough as the CA standard.

<u>V. Any uncertainty associated with the option</u>

This option has lots of uncertainty related to political and legal feasibility.

<u>VI. Level of agreement within the work group for this option</u> TBD.

Mitigation Option: Net Metering for Four Corners Area

I. Description of the mitigation option

Providing electricity consumers in the Four Corners area with net-metering agreements would allow each consumer to generate their own electricity from renewable resources to offset their electricity use. A net-metering law also mandates that a utility cannot charge more for your electricity than they pay you for the solar(renewable) power you generate. Net metering would make small house/business renewable systems more feasible.

Increased capacity of renewable energy systems in the Four Corners and around the world, will lead to less need for new coal-fired power plants and their associated emissions

EPA has just released a new edition of its Emissions and Generation Integrated Resource Database (eGRID). eGRID is a comprehensive source of data on the environmental characteristics of almost all electric power generated in the United States. It contains emissions and emissions rates for NOx, SO2, CO2 and mercury. The database also contains fuel use and generation data.
In the United States, electricity is generated in many different ways, with a wide variation in environmental impact. Traditional methods of electricity production contribute to air quality problems and the risk of global climate change. With the advent of electric customer choice, many electricity customers can now choose the source of their electricity. In fact, you might now have the option of choosing cleaner, more environmentally friendly sources of energy. According to the EGRID Power Profiler, it is possible to generate a report, for example about City of Farmington electricity use. EGRID provides fuel mixes, i.e. how is our power being generated. For Farmington the mix is approximately 13% Hydroelectric, 13% gas, and 74% coal. E-GRID also provides the corresponding emissions rate estimates. For Farmington, emissions rates associated with the electricity generation (lbs/MWh) are 3.1 NO2, 3.3 SO2, and 1873 CO2

Info on E-GRID is available at http://www.epa.gov/cleanenergy/egrid

Net metering programs serve as an important incentive for consumer investment in renewable energy generation. Net metering enables customers to use their own electricity generation to offset their consumption over a billing period by allowing their electric meters to turn backwards when they generate electricity in excess of their demand. This offset means that customers receive retail prices for the excess electricity they generate. Without net metering, a second meter is usually installed to measure the electricity that flows back to the provider, with the provider purchasing the power at a rate much lower than the retail rate.Net Metering Policy:

Net metering is a low-cost, easily administered method of encouraging customer investment in renewable energy technologies. It increases the value of the electricity produced by renewable generation and allows customers to "bank" their energy and use it a different time than it is produced giving customers more flexibility and allowing them to maximize the value of their production. Providers may also benefit from net metering because when customers are producing electricity during peak periods, the system load factor is improved.

There are three reasons net metering is important. First, as increasing numbers of primarily residential customers install renewable energy systems in their homes, there needs to be a simple, standardized protocol for connecting their systems into the electricity grid that ensures safety and power quality. Second, many residential customers are not at home using electricity during the day when their systems are producing power, and net metering allows them to receive full value for the electricity they produce without installing expensive battery storage systems. Third, net metering provides a simple, inexpensive, and easily-administered mechanism for encouraging the use of renewable energy systems, which provide important local, national, and global benefits

History:
On September 30, 1999, the New Mexico Public Regulation Commission (PRC) adopted a rule requiring all utilities regulated by the PRC to offer net metering to customers with cogeneration (CHP) facilities and small power producers with systems up to 10 kilowatts (kW) in capacity. Municipal utilities, which are not regulated by the PRC, are exempt. There is no statewide cap on the number of systems eligible for net metering.

For any net excess generation (NEG) created by a customer, the utility must either (1) credit or pay the customer for the net energy supplied to the utility at the utility's "energy rate," or (2) credit the customer for the net kilowatt-hours of energy supplied to the utility. Unused credits are carried forward to the next month. If a customer with credits exits the system, the utility must pay the customer for any unused credits at the utility's "energy rate." Customer-generators retain ownership of all renewable-energy credits (RECs) associated with the generation of electricity. [from DSIRE – Database of State Incentives for Renewable Energy – New Mexico]

Benefits:
Utilities benefit by avoiding the administrative and accounting costs of metering and purchasing the small amounts of excess electricity produced by these small-scale renewable generating facilities. Consumers benefit by getting greater value for some of the electricity they generate, by being able to interconnect with the utility using their existing utility meter, and by being able to interconnect using widely-accepted technical standards.

Tradeoffs: The main cost associated with net metering is indirect: the customer is buying less electricity from the utility, which means the utility is collecting less revenue from the customer. That's because any excess electricity that would have been sold to the utility at the wholesale or 'avoided cost' price is instead being used to offset electricity the customer would have purchased at the retail price. In most cases, the revenue loss is comparable to having the customer reducing electricity use by investing in energy efficiency measures, such as compact fluorescent lights and efficient appliances.

Special meters may also cost customer some installment costs

<u>II. Description of how to implement</u>

A. Mandatory or voluntary
Utilities should be required to providing Net metering arrangements for electricity users.

B. Indicate the most appropriate agency(ies) to implement
City of Farmington Utility, other Four Corners local utilities and Coops

Two comments were received on this option during the Task Force Report Public Comment Period:

“Not only do we need net metering with our local utility (Farmington Electric Utility System), it needs to be encouraged and not expensive to sign up. These are small steps toward diversifying our energy sources, and we are in a prime solar area for generating home-based electricity.”
“A net metering program would be positive if implemented with the proper subsidies to encourage citizens to get involved. Many people in the Four Corners area are not in the financial position to invest in the start-up program; this would have to come from state government programs for those who qualify.”

See all the public comments received for EEREC section in the appendix to this section.

III. Feasibility of the option

A. Technical

The standard kilowatt-hour meter used by the vast majority of residential and small commercial customers accurately registers the flow of electricity in either direction. This means the 'netting' process associated with net metering happens automatically-the meter spins forward (in the normal direction) when the consumer needs more electricity than is being produced, and spins backward when the consumer is producing more electricity than is needed in the house or building. [HP magazine, Net Metering FAQs]

It may be necessary to purchase a new meter.

B. Environmental

Use of renewable energy in the Four Corners area would offset emissions generated by polluting energy sources by approximately, 3.1 lbs NO_2, 3.3 lbs SO_2, and 1873 lbs CO_2 per MWh energy production.

Solar electric and wind energy systems can be expensive; however, if a systems design approach is used taking due account of conservation and energy efficiency, the system can be profitable.

C. Economic

Solar electric and wind energy systems can be expensive; however, if a systems design approach is used taking due account of conservation and energy efficiency, the system can be profitable.

Net-metering makes good economic sense. It is a fair approach and agreement between utility and consumer to buying and selling electricity

IV. Background data and assumptions used

1 Green Power Markets, Net Metering Policies
http://www.eere.energy.gov/greenpower/markets/netmetering.shtml

2 American Wind Energy Association: http://www.awea.org/faq/netbdef.html

3 Go Solar California Net Metering
http://www.gosolarcalifornia.ca.gov/solar101/net_metering.html

4 Database of State Incentives for Renewable Energy
http://dsireusa.org

5 Home Power Magazine, Net Metering FAQs:
http://www.homepower.com/resources/net_metering_faq.cfm

6. Solar Living Source Book, John Schaeffer, 2005

V. Any uncertainty associated with the option (Low, Medium, High) Low.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

Mitigation Option: New Programs to Promote Renewable Energy Including Tax Incentives

I. Description of the Mitigation Option

The Four Corners Region is recognized as having excellent solar and wind resources yet the incentives to use and develop renewable energy sources in Colorado (southwestern Colorado in particular) are extremely limited. For example, in Montezuma County, Colorado, net metering and the Federal Tax Credit for Solar Energy Systems are the only renewable energy incentives offered to residential power users. This mitigation option proposes several opportunities to diversify the incentives used to promote, develop, and increase the use of renewable energy in Colorado and other Four Corners states. The diversification of incentives will help Colorado in particular meet or exceed its current renewable energy standard (1), increase the overall use of renewable energy, reduce dependence on coal burning power sources, and reduce coal power plant emissions.

A 2003 report by the Union of Concerned Scientists gives "grades" to all states in the U.S. regarding the use and commitment to clean, renewable energy sources (2). Renewable energy sources include wind, geothermal, solar and bio-energy. In 2003, New Mexico received a grade "B+/B" (among the top 5 states in the nation) because of its commitment to increase the use of renewable energy by at least 0.5 percent per year. Currently, New Mexico has a renewable energy standard of 10 percent by the year 2011. In the same report, Colorado received a grade of "F" due to low levels of existing renewable energy and no commitment for future renewable energy development. This situation has improved since Colorado Amendment 37 passed in 2004 requiring a state-wide renewable energy standard. Colorado utilities are now required to obtain 3 percent of their electricity from renewable energy sources by 2007 and 10 percent by 2015. Even with the Colorado Amendment 37 law, incentives for encouraging the development of renewable energy in Colorado are extremely limited. There is tremendous opportunity to implement the many incentives already used in western states such as New Mexico, California and Nevada.

Incentives in this mitigation option would greatly accelerate the construction, maintenance, and expansion of solar and wind power generation. Wind and solar power sources create zero emissions of NOx, SOx, and CO2 (3). For this reason, solar and wind are the primary focus of this mitigation option.

INCENTIVES FOR RENERABLE ENERGY PROJECTS *

Incentive	**Description**	**Incentive Currently Offered?**		**Who Can Implement?**
		Colorado	**New Mexico**	**Authority**
Building Permit Fee Waiver for Solar Projects	Waive building permit fees when qualifying solar energy systems are installed in commercial/residential construction projects.	N	N	County/City
Leasing Solar Water Heating Systems	Service provider installs and maintains solar water heating systems for residents. Hardware owned and maintained by service provider. User pays installation fees and monthly utility fees based on system size.	N	N	Utility companies, city or county water & sanitation utilities
Renewable Energy Rebates/Credits	Rebates and/or credits (often based on system size) for purchase and	Only in a few areas,	N (?)	Utility companies

(System Costs)	installation costs of new grid-connected renewable energy systems that meet minimum energy efficiency qualifications.	including La Plata/Archuleta Counties.		
Renewable Energy Rebates/Credits (Net Metering)	Rebates and or credits for excess energy produced from grid-connected renewable energy systems.	Y	Y	Utility companies
Tax Deduction/Credit #1	Tax deduction or credit for 100% of the interest on loans made to purchase renewable energy systems or energy efficient products and appliances.	N	N	States
Tax Deduction/Credit #2	Property Tax deduction for qualifying solar photovoltaic systems.	N	N	States
Tax Deduction/Credit #3	Corporate income tax credit for companies with qualifying low or zero emissions renewable energy systems > 10 MW	N	Y	States
Tax Deduction/Credit #4	Personal income tax credit (plus Fed. Tax credit) up to 30% or $9,000 for on or off-grid photovoltaic and solar hot air systems.	N	Y	States
Sales tax exemption for Biomass Equipment and Materials	Commercial and industrial sales tax (compensating tax) exemption for 100% of the cost of material and equipment used to process biopower.	N	Y	States
Supplemental Energy Payments (SEP's)	SEPs are made for eligible renewable generators to offset above-market costs of investor-owned utilities to meet their renewable energy standard portfolio obligations.	N	N	States
Bond Programs for Public Buildings	Bonds provided to schools and public buildings to upgrade to energy efficient heating/lighting or installation of renewable energy power systems. Bonds paid back through savings on energy bills.	N	Y	States
Grant Programs	Grants provided for up to 50% of the cost of design, installation and purchase of renewable energy systems for residential and commercial/industrial	N	N	Utilities, States, residences
Energy Efficient Standards for State	Requirement for all new public building construction to achieve US	Only where economical	Y	States, local governments in

Buildings	Green Building Council Leadership in Energy and Environmental Design (LEED) ratings based on size. LEED systems emphasize energy efficiency and encourages use of renewable energy sources.	ly feasible		Colorado
Loan Programs	Zero interest loans offered for qualifying photovoltaic and solar water heat systems	Only a few locations, none in SW Colorado	N	Local communities, utilities and financial partners

* Incentives in this table were developed by comparing incentives currently used in New Mexico, California, Nevada, and Colorado (4)

Benefits: Incentives will be necessary to increase the use of renewable energy, especially for the typical residential power user. Colorado's renewable energy program is relatively new and is stimulating a developing renewable energy market. The timing is very good to implement and support a diverse incentive program to meet or exceed the State's renewable energy standard, and increase the overall use of renewable energy. An increased use of clean renewable energy will result in a corresponding decrease in NOx, SOx, and CO2 produced by coal-fired power generation.

Tradeoffs: Several incentive options would require legislation or other mechanisms of State governments and would require some time to set in place. Many incentives would be offered by State government in the form of tax incentives and may slightly decrease State tax revenues. The use of incentives listed in the above table by several western states is a good indication they work effectively and provide value to that State. They can be implemented by Colorado and other Four Corners region states.

II. Description of How to Implement

A. Voluntary or mandatory – Incentives, by definition, would be voluntary for the consumer. It could be voluntary or mandatory for the States, local government, or utility companies to offer the incentives.

B. Indicate the most appropriate agency(ies) to implement – See Incentives Table above for appropriate agency for each incentive measure.

III. Feasibility of the Option

Public and corporate knowledge regarding the environmental benefits and cost benefits of solar and wind alternative energy systems is limited, and could be greatly improved. The diversification of incentives could stimulate interest in renewable energy systems.

A. Technical: The technology for wind and solar power systems, and solar water heating and space heating is currently widely available. Improvements to make these technologies more efficient and affordable is ongoing. Using incentives to increase the use and demand for these systems would stimulate further technological advances.

B. Environmental: A 10 percent increase in the use of renewable energy in Colorado will result in a reduction of 3 million metric tons of CO2 per year in 25 years (5). It would also result in the reduction of SO2 and NOx.

C. Economic: 1) Increased demand and use of solar and wind energy systems will stimulate accelerated improvements in solar and wind energy technology and reduce costs of the technology in the long term. 2) Implementing incentives for individuals and corporate/businesses will stimulate and accelerate the use of existing wind and solar technologies. 3) Increased use through incentives will create an expanding market for producers (6), and could create up to 2,000 new jobs in Colorado in manufacturing, construction, operation, and maintenance and other industries in 25 years (5) 4) Increased use of the technology would reduce and energy costs to consumers and insulate the economy from fossil fuel price spikes (7).

IV. Background Data and Assumptions Used

(1) A renewable energy (or electricity) standard is a requirement by a state or the Federal government for utilities to gradually increase the portion of electricity they produce from renewable energy sources.

(2) Union of Concerned Scientists, 2003. Plugging in Renewable Energy, Grading the States. www.ucsusa.org/clean_energy

(3) American Wind Energy Association, 2006. Wind Energy Fact Sheet – Comparative Air Emissions of Wind and Other Fuels. 122 C Street, Washington, D.C., 2 pp.; citation for solar).

(4) Database of State Incentives for Renewable Energy (DSIRE), 2006. New Mexico, Colorado, Nevada, and California Incentives for Renewables and Efficiency. www.dsireusa.org/ ; Governor's Office of Energy Management and Conservation, 2006. Rebuild Colorado, Utility Incentives for Efficiency Improvements and Renewable Energy. www.colorado.gov/rebuildco ; Martinez, Louise, 2006. Presentation to the Four Corners Task Force – New Mexico Clean Energy Programs. New Mexico Energy, Minerals, and Natural Resource Department, presentation in Farmington NM, November 8.

(5) Union of Concerned Scientists, 2004. The Colorado Renewable Energy Standard Ballot Initiative: Impacts on Jobs and the Economy. www.ucsusa.org/clean_energy/clean_energy_policies/the-colorado-renewable-energy-standard-ballot-initiative.html

(6) Gielecki, Mark, F. Mayes, and L. Prete, 2001. Incentives, Mandates, and Government Programs for Promoting Renewable Energy. Department of Energy, 26 pgs. www.eia.doe.gov/cneaf/solar.renewables/rea_issues/incent.html

(7) Union of Concerned Scientists, 2006. Renewable Energy Standards at Work in the States. http://www.ucsusa.org/clean_energy_policies/res-at-work-in-the-states.html

V. Any Uncertainty Associated With the Option (Low, Medium, High)

Low – Increasing the use of renewable energy sources is widely accepted as a practice which will decrease air pollution emissions associated with burning fossil fuels. Increasing incentives would increase the widespread use of renewable energy systems.

VI. Level of Agreement within the Work Group for this Mitigation Option TBD.

VII. Cross-over Issues to the Other Source Groups None at this time.

Mitigation Option: Promote Solar Electrical Energy Production

I. Description of the mitigation option

A. Promote Solar Electrical Energy Production:
The region in general has good solar energy possibilities, a large number of clear days with very few successive days of clouds. If storage was not used it means that there would be power to feed to the distribution system during peak solar intensity. The power density is also quite favorable being in the range of 600 to1000 W/m2 for peak values (winter, summer). In the summer this would match the large load of air-conditioning, it would not match the winter load. Solar electrical has a developed technology with standards and while the systems are complex, especially if feedback to the power grid is done, it is not beyond the capabilities of trained people in the area.

B. Reduce Electrical Energy Consumption by Substituting Solar Energy:
The reduction of electrical energy consumption for home heating and hot water production can be replaced or supplemented by solar energy inputs. These would be significant for the individual household but these households are a small percentage of the general population. All buildings use solar energy, it is just a matter of degree. All can be improved to make better use of the solar energy which we have available, reducing other energy consumption.

II. Description of how to implement

A. Mandatory or voluntary:
Voluntary on the part of the person with the solar electric installation and with agreement of the electric utilities company, possibly with legal control by the state. Utilities would specify interconnect requirements.

B. Indicate the most appropriate agency(ies) to implement
Utilities/State

III. Feasibility of the option

A. Technical: For solar electrical systems, new inspectors would be needed or present ones reeducated. You may need a change in distribution control system.

B. Environmental: The environmental results of shifting the energy consumption from fuels (gas, oil, coal) burned in the region to solar means a reduction of all types of air pollutants by what ever reduction was achieved.

C. Economic: Not that practical unless the person is far off the grid. Would most likely need incentives (tax?). Large capital out lay to replace ongoing expenses of fuel. If other energy sources are replaced by solar, taxes will be lost.

D. Political: Since regulation and taxes may be involved this could be a problem.

IV. Background data and assumptions used:

6000-7000 heating degree days for the region
1500 cooling degree days for the region
6 usable solar hours per day (yearly average).
5 usable solar hours per day (winter average)

V. Uncertainty associated with the option (Low, Medium, High):

Low for would it work, High for could you get enough people doing it to have a significant affect.

VI. Level of agreement within the Work Group for this option TBD

VII. Cross-over issues to the other source groups None

Mitigation Option: Subsidization of Land Required to Develop Renewable Energy

I. Description of the mitigation option

Land required for larger renewable energy projects, especially solar electric energy production, would be subsidized. This option would help to promote and make renewable energy production more feasible.

BLM/FS has a large amount of unused land. Some large renewable energy projects could be demonstrated on that land. A collaborative program should be developed with US Government owners of NW NM land to provide cheap or in some case potentially free land leases to companies that are willing to develop renewable energy production facilities. Barriers should be reduced.

The Navajo Nation and other tribes in the Four Corners area own a large amount of land in the Four Corners area. There has been some interest in wind energy development on Native American land in Arizona. Available land resources on the reservation could be used to develop renewable energy projects and stimulate the local economy.

Benefits: Solar electric energy is clean energy.
Solar electric energy production could complement and eventually displace coal fired power plant electricity generation. Eventually, over time, promotion and expansion of solar electric energy production could replace the need for a new coal-fired power plant. This alternative strategy to energy production would then displace the air pollution emissions associated with that power plant.

Solar electric energy development in the Four Corners area would stimulate the photovoltaic equipment and service industry here.

Burdens: Land resource would be needed (see feasibility section). We have estimated the amount of land required to generate 1 MW of solar electric capacity.

II. Description of how to implement

A. Mandatory or voluntary
Mandatory. A rule would need to be created describing the subsidization amount and conditions.

B. Indicate the most appropriate agency(ies) to implement
Four Corners government property owners such as BLM, FS, and Navajo Nation

III. Feasibility of the option

A. Technical
The amount of land required to produce 1 MW solar electric generation capacity

For Farmington, NM a Flat-plate collector on a fixed-mount facing south at a fixed tilt equal to latitude, sees avg. of 6.3 hours of full sun. Full sun is 1,000 watts per square meter.

For our estimation we will use large Evergreen Cedar-series ES-190 W Spruce Line Module with MC Connectors, rated by California Energy Commission, http://www.consumerenergycenter.org/cgi-bin/eligible_pvmodules.cgi, at 166.8 watts output.

Based on our location in Farmington, 166.8 watts x 6.3 hours, we have a per day 1050 watt-hr per day per module. Module is approximately 61.8" x 37.5", surface area is 16.1 square feet. Allow extra space and we will need approximately 20 square feet per module.

Assume DC output to conventional AC power conversion inefficiency of 95%, CEC

1.05 KWh per module per day is reduced to approx 1 KWh at AC grid.

Conversion: 43,560 square feet in an acre
2178 modules could be fit on area of 1 acre.
This # of PV modules would generate approximately 2.2 MWh of energy.
At Farmington site this corresponds to approximately 345 KW of solar electric generation capacity.

Therefore, we could fit could generate 1 MW of electricity during daylight hours on about 3 acres of land in Farmington. Based on the solar irradiance values for Farmington this would be about 2.2 MWh of energy per day.

[Real Goods Solar Living Sourcebook, John Schaeffer, 12th edition, 2005, p.57 method of design used]

B. Environmental: Photovoltaic modules do not have significant negative environmental costs

C. Economic: Each module in example would cost approximately $1,000. There is a large amount of open land available, not in use, on government land in the 4 Corners area. Renewable energy projects could provide local jobs and help economy.

IV. Background data and assumptions used

1. California Energy Commission, http://www.energy.ca.gov/, PV specifications
2. Evergreen Solar PV module product information, http://www.evergreensolar.com/
3. Farmington, NM Solar Insolation data from San Juan College Renewable Energy Program

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other Task Force work groups None

Mitigation Option: Use of Distributed Energy

I. Description of the mitigation option

Distributed energy refers to decentralized generation and use of relatively small amounts of power, usually on demand in a local setting. Excess power may or may not be delivered to the grid. This option would encourage the use of distributed energy by owners of residential or commercial buildings or neighborhoods, where practical and feasible. While it is generally accepted that centralized electric power plants will remain the major source of electric power supply for the future, distributed energy resources (DER) can complement central power by providing incremental capacity to the utility grid or to an end user. Installing DER at or near the end user can also benefit the electric utility by avoiding or reducing the cost of construction of new plants to meet peak demand and/or of transmission and distribution system upgrades.

Distributed energy encompasses a wide range of different types of technologies. The Department of Energy, the state of California and various trade groups have programs encouraging research into and use of these technologies. Distributed energy technologies are usually installed for many different reasons. This option focuses on any distributed energy options that reduce demand on grid sources and thereby reduce the demand for new large power plants and/or transmission costs. While excess power generated by distributed sources and delivered to the grid can aid in reduction of power demand on centralized sources, distributed energy options are also important in serving needs in areas not currently attached to the grid thereby reducing the need for hookup to the grid.

Since these technologies are individual and/or local in nature, the burden would be on the prospective homeowner and building owner to seek out options and financing and a contractor who is sufficiently knowledgeable to suggest options and skilled enough to implement them. Initially, mortgage support or grants may also be needed to encourage implementation.

For the environmentally conscious consumer, the use of renewable distributed energy generation and "green power" such as wind, photovoltaic, geothermal or hydroelectric power, can provide a significant environmental benefit. However, the potential lower cost, higher service reliability, high power quality, increased energy efficiency, and energy independence are additional reasons for interest in DER.

II. Description of how to implement

The choice to use distributed energy resources and specifically which one(s) are appropriate should be voluntary. The decision can involve higher capital costs, and the willingness to invest in technologies that may be new and not widely implemented. Federal, state and local departments of energy should support research into options most suited to a particular geography and climate; loans and grants should be available and experts should be retained to consult with potential users.

III. Feasibility of the option

A. Technical – Information on various choices is available, choices range from low-tech to high-tech
B. Environmental – Any options that reduce the demand on the centralized power grid and minimize their own pollution will contribute to an improved environment by reducing the need for coal-fired power plants in our area
C. Economic – Options range in cost. Greater use of options should ultimately result in reduced unit costs
D. Political – Use of distributed energy resources should be an easy sell politically; the degree to which federal and state research and resources are already available, indicates a public commitment already in place

IV. Background data and assumptions N/A

V. Uncertainty – This option has a high degree of certainty that it could be implemented and be effective.

VI. Level of agreement within the work group for this option TBD

VII. Cross-over issues to the other source groups None at this time.

CONSERVATION

Mitigation Option: Changes to Residential Energy Bills

I. Description of the mitigation option

Energy for many households in the four corners area is delivered as electricity and/or natural gas. Residential energy is used for home heating, hot water, and to run appliances. Most residential consumer receives monthly bills. Examples of typical electric and gas bills are shown in Figures 1 and 2, respectively.

Figure 1. Residential electric utility bill with sample energy cost savings

Electric Association Bill (Colorado)

Account Information

SERVICE DATE		NO. DAYS	RTE/SEQ	METER READING		MULTI PLIER	kWh USAGE	CHARGES
PREVIOUS	PRESENT			PREVIOUS	PRESENT			
9/18/2006	10/16/2006	28	403-160	1	612	1	612	

LAST AMOUNT BILLED	95.07	
PAYMENT MADE -- THANK YOU	95.07	CR
…….		
ENERGY CHARGES	54.30	
CITY TAX	2.97	
BASIC CHARGE	15.50	
FRANCHISE FEE	3.49	
TOTAL CURRENT CHARGES	76.26	

COST COMPARISON	DAYS SERVICE	TOTAL kWh	AVG. kWh/DAY	kWh COST/DAY
CURRENT BILLING PERIOD	28	612	22	2.72
PREVIOUS BILLING PERIOD	34	806	24	2.24
SAME PERIOD LAST YEAR	28	676	24	2.72

TOTAL DUE	76.26
BILLING DATE:	10/20/2006
DUE DATE:	11/6/2006

Example of possible cost savings for an electric hot water heater			
Most efficient	4622	kW/yr	
Anticipated monthly saving in kWh/yr		21	kWh
Monthly dollar saving @ your rate of 12.5 cents / kWh		2.65	
Savings over a 13 year life		412.78	

Figure 2. Residential gas utility bill with sample energy cost savings

Energy (gas) Company Bill (Colorado)

DATE OF SERVICE		METER READING	
FROM	TO	PREVIOUS	PRESENT
10/02/06	11/01/06	9750	9845

RATE CODE:	36QC
USAGE IN CCF:	78
PRESSURE FACTOR:	0.819

BILLING INFORMATION:			
METER DEPOSIT	347.00		
PREVIOUS BALANCE			
CURRENT GAS CHARGE TOTAL		85.15
FACILITY CHARGE	21.50	
COM LDC COST @ .16000/CCF	12.45	
UPSTREAM COST @ .02530/CCF	1.97	
COMMODITY COST @ .67930/CCF	52.86	
DEFERRED GAS COST @ -.09880/CCF	-7.69	
FRANCHISE FEE @ .05000	4.06	
SERVICE CHARGE TOTAL		0.54
PENALTY	0.54	
TAX TOTAL		
STATE TAX @ .02900	2.47	
CITY TAX @ .04050	3.44	
COUNTY TAX @ .00450	0.38	
CURRENT CHARGES		91.98
TOTAL AMOUNT DUE		91.98

Usage this month	95	therms	
Example of possible cost savings for a gas hot water heater			
Most efficient	230	therms/year	
Anticipated monthly saving in therms		4	kWh
Monthly dollar saving @ your rate of 0.97 cents		3.88	
Savings over a 13 year life		605.28	

A typical energy bills lists meter readings, cost breakdowns, and other technical information. Much of the information on monthly energy statements is required by regulatory bodies and laws. Most importantly, a typical bill does not provide the consumer with information to make decisions on energy conservation and the ability to translate proposed conservation options to dollars saved.

The suggested mitigation option is to have an additional place on monthly bill that would feature one energy conservation step that a consumer may take and indicate cost savings. In the examples presented, a cost saving for a new energy efficient hot water heater is shown (bold box in Figure 1 and in Figure 2). Another monthly statement could show the amount of savings that may result from lowering the thermostat one degree Fahrenheit. A statement of energy saving on the bill would be more effective that simply including a generic insert in the bill. These often are quickly discarded.

In addition, we recommend that all energy bills have a graph that shows 1) year to month energy used for the current and past year and monthly use comparing the current to the previous year.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary
B. Indicate the most appropriate agency(ies) to implement:
Energy companies

III. Feasibility of the option

A. Technical: Some reprogramming of residential energy billing program
B. Environmental:
C. Economic: Cost of reprogramming software

IV. Background data and assumptions used

V. Any uncertainty associated with the option (Low, Medium, High) Medium

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other Task Force work groups: Unknown

Mitigation Option: County Planning of High Density Living as Opposed to Dispersed Homes throughout the County

I. Description of the mitigation option
San Juan County is presently starting the process of developing a county wide growth master plan. A number of questions in their citizens questionnaire were if there should be encouragement or restrictions in development of home sites in the rural areas of the county and if this growth should be low or high house value. From the point of view of energy conservation and hence reduced pollution of many types the county should be encouraged to develop a plan which encourages clustering of housing (not in the far rural areas) so as to reduce energy losses on distribution lines and the reduction of travel distances for transportation. The ideal clustering should be near employment and services. Other counties in the Four Corners should be encouraged to also follow this pattern.

II. Description of How to Implement:
A. Mandatory or voluntary
While you cannot force people to do this, encouragement by tax policies, varying rates based on distances for electrical services, zoning or other methods would be helpful.
B. Indicate the most appropriate agency(ies) to implement

Taxes and zoning would be under the county government while the rates would be with the electric utilities companies of allowed by law. I do not know how much latitude they have.

III. Feasibility of the option
A. Technical: No problems

B. Environmental: None until specifics are assumed.

C. Economic: Concentrated populations, within limits, will have an advantage of reduced infrastructure coast.

D. Political: The greatest problem with this option will be general resistance to the ideal by the general public and very great resistance from those with vested interest.

IV. Background data and assumptions used San Juan county citizens' questionnaire.

V. Uncertainty associated with the option (Low, Medium, High) TBD.

VI. Level of agreement within the Work Group for this option TBD.

VII. Cross-over issues to the other source groups None at this time.

Mitigation Option: Direct Load Control and Time-based Pricing

I. Description of the mitigation option

Overview
This option describes demand response tools focused on direct load control and electric pricing. By offering direct load control and electric pricing options around time-of-day, critical peak and seasonal use, customers are provided with an effective price signal regarding when and how they use electricity. Demand response ("DR") is the label currently given to programs that reduce customer loads during critical periods. In the past, DR programs have also been called "load management" and "demand-side management" programs. Most demand response programs currently focus on either peak load clipping through direct load control or load shifting through time-based pricing mechanisms. The primary goal of DR programs is to reduce peak demand. The concerns regarding impending major capital expenditures by utilities for additional generating and transmission system capacity and the impact of energy consumption on the environment has sparked a renewed interest in utility programs to reduce the amount of energy used during periods when the generation and power delivery infrastructures are most constrained and at their highest costs. Reductions in peak demand may or may not be accompanied by a reduction in the total amount of energy consumed. This is because DR programs may result in energy consumption simply being shifted to a period when the utility system is not as constrained and market prices are lower.

Air Quality and Environmental Benefits- Demand response programs primary purpose is to reduce peak load. These programs may not lead to energy conservation nor should they be relied upon to do so (Energy efficiency programs are specifically designed to reduce the total amount of energy used by customers on an annual basis).
These programs may allow utilities to hold off on building new generating plants and permit technology to develop and mature in the areas of clean coal generation as well as renewable energy.
(As an indirect benefit, if customers do choose to conserve energy, the reduction in energy use may lead to a reduction in the need for energy generation resulting in emission reductions in air pollution and greenhouse gases).

Economic: Customer charge for the installation and use of automatic metering systems (where applicable) installed in participating residential and commercial customer homes and businesses
Cost to utility for administration and tracking of the program.

Trade-offs: Positive public relations, clean coal and renewable technology maturation

II. Description of how to implement

Mandatory or voluntary: Voluntary
Time of use pricing: Electricity is priced at two different levels depending upon the time of day. The inverted block rate is a rate design for a customer class for which the unit charge for electricity increases from one block to another as usage increases and exceeds the first block. The incentive is to use less energy and stay within the first block, which has the lowest rates.

Critical peak pricing: Critical peak pricing is a pricing scheme that encourages customers to reduce their on and mid-peak energy usage by offering incentives through an alert-based, monitoring system.

Seasonal use pricing: Electric rates vary depending upon the time of year. Charges are typically higher in the summer months when demand is greater and the cost to generate electricity is higher. For example, during the months of June through September, electricity rates would be higher than other months.

The public utility commission is the most appropriate entity to implement.

III. Feasibility of the option
Technical: Good feasibility. Programs have been applied and demonstrated at utilities across the country. Automated and advanced metering systems are commercially available.
Environmental: Medium feasibility for indirect benefits. Prices and advanced metering systems can be used to modify customer behavior to use less electricity within individual homes and businesses during peak hours. This may or may not lead to energy conservation. However, such programs may allow utilities to hold off adding new generation assets, thereby, improving opportunities for employment of more advanced, demonstrated and cost-effective clean coal and renewable energy technology.
Economic: Good economics. Advanced metering systems, in addition to better enabling time-based rates, can deliver load control signals to end-use equipment and provide consumers with energy consumption and price information to assist with shifting load from on-peak to off-peak periods, thereby saving the customer money on their utility bills. Direct load control and electric pricing options create long-term market transformations by shifting energy use to periods of lower plant and infrastructure constraints as well as lower market cost. As a result, utility maintenance and equipment replacement costs may be reduced and the cost to build new generation may also be postponed.

IV. Background data and assumptions used
Energy Administration Information, Department of Energy
Federal Energy Regulatory Commission, "Assessment of Demand Response & Advanced Metering"
Conservation is not the purpose of direct load control and electric pricing options. Energy efficiency programs are better suited to promote conservation.

V. Any uncertainty associated with the option (Low, Medium, High) Medium. Voluntary programs do not guarantee energy conservation and emissions reductions.

VI. Level of agreement within the work group for this mitigation option Good. This option write-up stems from a discussion at the November 8, 2006 meeting of the Power Plant Working Group.

VII. Cross-over issues to the other source groups (please describe the issue and which groups)
Other Sources Group- Pilot Neighborhood Project to Change Behavior to Reduce Energy Use and Energy Efficiency Programs

Mitigation Option: Energy Conservation by Energy Utility Customers

I. Description of the mitigation option

This option would require all generators of power (renewable and non-renewable sources) in the Four Corners area to develop a program which causes their customer base to reduce per capita power usage each year for five years until an agreed upon endpoint is reached. The owners of all facilities that generate power, irrespective of how it is generated, should be required to develop or participate in a program which encourages their customer base to reduce per capita, per household, per production unit (or whatever other measure is equivalent for non-residential customers) use of power each year for five years until some reasonably aggressive endpoint is reached. The percent annual reduction would be 20% of the difference between the baseline usage and the five year goal.

The goal or endpoint would be negotiated between industry trade groups, governmental agencies, environmental groups and interested parties and would vary depending on the climate at the location of the customer base. The set of endpoints thus determined would apply industry-wide and always be a challenge. Most measures observed to date depend on a percent reduction in per unit usage. The difference in this option is that the endpoint for each customer base is a specific achievable minimum amount of energy usage based on current technology.

This concept is similar to water conservation programs, which have successfully reduced water usage. Water companies have used incentives to promote the use of water saving devices – low water flush toilets, controls on shower heads, more efficient outdoor sprinkling systems.

Power generators could develop their own programs or join together with other power producers in a consortium to implement a program. Customers could be rewarded with financial incentives such as reduced costs per unit for reduced levels of usage and/or lesser rates for power used at off-peak times of the day or week. Conservation credits could be traded as in the pollution credit trading program as long as the caps were reduced each year until the overall goal for that customer base is met.

A web site devoted to success and failure of conservation incentive programs, publicizing the progress of each power plant could impact compliance by affecting shareholder decisions, among other things. The American Council for an Energy Efficient Economy has a start on this with their study 'Exemplary Utility-Funded Low-Income Energy Efficiency Programs' (www.aceee.org).

The burden of this requirement would be on the power generators and indirectly on the customer base. The goals for each power generating plant should be aggressive but attainable for their customer base. When a plant has multiple customer bases, appropriate goals should be set for each base separately, in consideration of differences in climate.

II. Description of how to implement

This rule should be mandatory for all power generators. Many power generators have such programs now but should be required to look at best practices (most cost-effective programs) for these programs and implement them.

A loan-incentive program may be needed to help owners of large buildings replace costly appliances such as hot water heaters, refrigerators, heating and air conditioning units, which can achieve high energy savings.

III. Feasibility of the option

Technical: Programs motivating conservation exist.

Environmental: The environmental benefits include reduced pollution which accompanies reduced power generation relative to what it would have been either at peak times or over time, depending on success of customer conservation program. Over time fewer power generating facilities would need to be built (or older inefficient units could be retired sooner)
Economic: Programs will cost money, but they are cost-effective (see data below). Implementation could be contracted out
Political: Probably minimal challenge in getting this requirement passed, this is pretty innocuous; and the public relations campaign around conservation would educate consumers as to their role and potential impact on reducing greenhouse gases, reducing air pollution and improving air quality

IV. Background data and assumptions
(1) Southwest Energy Efficiency Project (SWEEP): Highlights taken from SWEEP's website, http://www.swenergy.org/factsheets/index.html:

The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest examines the potential for and benefits from increasing the efficiency of electricity use in the southwest states of Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming. [Unfortunately, California is not included.] The study models two scenarios, a "business as usual" Base Scenario and a High Efficiency Scenario that gradually increases the efficiency of electricity use in homes and workplaces during 2003-2020.

Major regional benefits of pursuing the High Efficiency Scenario include:

- Reducing average electricity demand growth from 2.6 percent per year in the Base Scenario to 0.7 percent per year in the High Efficiency Scenario;
- Reducing total electricity consumption 18 percent (41,400 GWh/yr) by 2010 and 33 percent (99,000 GWh/yr) by 2020;
- Eliminating the need to construct thirty-four 500 megawatt power plants or their equivalent by 2020;
- Saving consumers and businesses $28 billion net between 2003-2020, or about $4,800 per current household in the region;
- Increasing regional employment by 58,400 jobs (about 0.45 percent) and regional personal income by $1.34 billion per year by 2020;
- Saving 25 billion gallons of water per year by 2010 and nearly 62 billion gallons per year by 2020; and
- Reducing carbon dioxide emissions, the main gas contributing to human-induced global warming, by 13 percent in 2010 and 26 percent in 2020, relative to the emissions of the Base Scenario.

These significant benefits can be achieved with a total investment of nearly $9 billion in efficiency measures during 2003-2020 (2000 $). The total economic benefit during this period is estimated to be about $37 billion, meaning the benefit-cost ratio is about 4.2. The efficiency measures on average would have a cost of $0.02 per kWh saved.

The High Efficiency Scenario is based on the accelerated adoption of cost-effective energy efficiency measures, including more efficient appliances and air conditioning systems, more efficient lamps and other lighting devices, more efficient design and construction of new homes and commercial buildings, efficiency improvements in motor systems, and greater efficiency in other devices and processes used by industry. These measures are all commercially available but underutilized today. Accelerated adoption of these measures cannot eliminate all the electricity demand growth anticipated by 2020 in the Base Scenario, but it can eliminate most of it.

(2) US Department of Energy – Energy Efficiency and Renewable Energy, a consumer's guide: http://www.eere.energy.gov/consumer/ List of suggestions for consumers includes many of the items mentioned in SWEEP's High Efficiency Scenario and focuses on proper operation of the items.

V. Uncertainty

No uncertainty about benefits of conservation; moderate uncertainty about how much consumers will cooperate and actually conserve.

VI. Level of agreement TBD.

VII. Cross-over issues

Need discussion as to how it would fit into Oil and Gas Group's sources

Mitigation Option: Outreach Campaign for Conservation and Wise Use of Energy Use of Energy

I. Description of the mitigation option

Conservation is an important strategy for mitigation air pollution in 4 Corners area. An outreach campaign centered on this strategy would help to educate public and industry and lead to more conservation actions. This would lead to a sustainable future, reduce dependence on fossil fuels, and help to mitigate air pollution in the Four Corners area.

Conservation is defined as the sustainable use and protection of natural resources including plants, animals, minerals, soils, clean water, clean air, and fossil fuels such as coal, petroleum, and natural gas. Conservation makes economic and ecological sense. There is a global need to increase energy conservation and increase the use of renewable energy resources.

Coal fired power plants are the nation's largest industrial source of the pollutants that cause acid rain, mercury poisoning in lakes and rivers and global warming. Utilizing renewable energy sources such as wind and solar and improving energy efficiency in appliances, business equipment, homes, buildings, etc. will theoretically reduce pollution from coal fired power plants. Of course, installation of best management pollution control equipment on existing coal fired power plants will be most beneficial.

Renewable energy alternatives such as solar, water, and wind power and geothermal energy are efficient and practical but are underutilized because of the availability of relatively inexpensive nonrenewable fossil fuels in developed countries. Conservation conflicts arise due to the growing human population and the desire to maintain or raise the standards of living.

Up until now, consumer behavior has been motivated by cheap and plentiful energy and not much thought has been given to the degradation of the environment. Production and use of fossil fuels damage the environment. The supply of nonrenewable fossil fuels is limited and is rapidly being used up. Fossil fuel is becoming more expensive. Reality is beginning to set in. There is a need for safe, clean energy production, renewable energy alternatives, and conservation. Energy supplies and costs will restructure consumer usage.

Federal and State agencies and the utility companies need to focus on more public awareness and provide information on available tax credits for solar, photovoltaic, and solar thermal systems. There are also tax credits available to homeowners for replacement of older air conditioners, heat pumps, water heaters, windows, and installation of insulation. There are tax incentives for the purchase of hybrid automobiles.

All of this information is available on web sites, tax forms, agency handouts, etc. but, more than likely, the average citizen is unaware. Since alternative energy and conservation have moved to the forefront, the public needs information. Public service announcements on TV, radio and newspapers and informational mailings in consumer energy billings would be most helpful.

School children should be included in the energy information process. There is a program for grades K - 4 titled "Energy for Children - All about the Conservation of Energy" with a teacher's guide that is available on www.libraryvideo.com.

The educational programs need to start in elementary school (or earlier) and continue through high school. There are some really great opportunities for curriculum development in energy conservation that would integrate several disciplines including biology, math, and social studies. I think NM has done the best job of this among the four corner states and hope that it will be expanded to the other states. It would be good just to have a group review K-12 materials, see what gaps exist and how information, including successes can be promulgated. Perhaps this has been done - a web site is a good start.

A Google search of "conservation of energy resources" has a very large website database.

Volunteer groups are working to improve the energy efficiency of homes occupied by the elderly and by people who are unable and/or cannot afford to make home improvements.
Communities could work toward increasing the volunteer workforces and the resources for this much needed humanitarian service.

The future belongs to our children and grandchildren. What we have done in the past and what we do in the here and now, has a direct impact on the environment that future generations will inherit.

II. Description of how to implement
A. Mandatory or voluntary
Voluntary at grassroots and governmental levels
Some mandatory curriculum could be developed for schools as part of educational component

B. Indicate the most appropriate agency(ies) to implement
Local Governmental Energy and Air Quality Agencies. Schools

III. Feasibility of the option
A. Technical: We must clearly demonstrate the problems and potential solutions

B. Environmental: Conservation has been shown to reduce energy use

C. Economic: Outreach program must demonstrate the short term economic benefits. Also design program to benefit low-income citizens. Government needs to provide some economic incentives to help kick start conservation programs

IV. Background data and assumptions used N/A.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups All Work Groups.

CROSSOVER OPTIONS

Mitigation Option: Bioenergy Center
(Reference as is from Power Plants: see Future Power Plants section)

Mitigation Option: Biomass Power Generation
(Reference as is from Power Plants: see Future Power Plants section)

Mitigation Option: Utility-Scale Photovoltaic Plants
(Reference as is from Power Plants: see Future Power Plants section)

ENERGY EFFICIENCY, RENEWABLE ENERGY AND CONSERVATION: PUBLIC COMMENTS

Energy Efficiency / Renewable Energy / Energy Conservation Public Comments

Comment	Mitigation Option
Advanced metering for home owners will not work. It will only enrich the electric companies who will use the data to set rates higher when people need the energy. An alternative is rolling blackouts on house AC's like that used in the Houston, TX area.	Advanced Metering
Using combined heat and power could be an effective method to increase efficiency and reduce emissions.	Cogeneration/Combined Heat and Power
The Four Corners region has a huge potential to develop renewable energy resources. Moreover, our resources are not limited to good sun and the region's many windy plateaus. Our citizenry possesses a large body of technical expertise, many of whom already work in energy and electrical power generation. We also have mechanical expertise and a pre-existing industrial infrastructure at our hands. Last, we are extremely well-suited to implement educational programs for renewable energies. Dineh College, San Juan College, and Fort Lewis College are obvious examples. This option can also sustain us beyond the inevitable decline in oil and gas production, as well as providing a means for younger generations to stay and work in their home areas (which is especially problematic in La Plata County.) Last, this possibility fits neatly with the previous recommendation for a regional planning board or authority. In short, we have every reason in the world implement renewable energy as a regional industry.	Renewable Energy
Pure protectionism, not good energy policy. The NIMBY attitude will never solve problems. If you want clean energy, do it the right way, build nuclear. I notice that this option never came up why?	Four Corners States Adopt California Standards for Purchase of Clean Imported Energy
Not only do we need net metering with our local utility (Farmington Electric Utility System), it needs to be encouraged and not expensive to sign up. These are small steps toward diversifying our energy sources, and we are in a prime solar area for generating home-based electricity.	Net Metering for Four Corners Area
A net metering program would be positive if implemented with the proper subsidies to encourage citizens to get involved. Many people in the Four Corners area are not in the financial position to invest in the start up program; this would have to come from state government programs for those who qualify.	Net Metering for Four Corners Area

Cumulative Effects

Cumulative Effects: Preface

Overview

The Cumulative Effects work group was charged with assisting the source work groups to understand current and future air quality conditions in the region, using existing information. The cumulative effects workgroup was also to assist the other work groups in performing their analysis of the mitigation strategies being developed, within the scope of the Task Force's timeframe and resources. The Cumulative Effects work group was also tasked with suggesting ways for filling technical gaps and addressing uncertainties as identified by the other work groups.

The Cumulative Effects work group was a small group with approximately a half dozen active members representing state governments, tribal governments, local citizens, industry, and the federal government.

Scope of Work

The following was the original scope of work for the Cumulative Effects (CE) work group.

Specific Tasks:

1. Evaluate air quality effects of candidate mitigation measures as requested by other Task Force work groups, or provide guidance on how candidate mitigation measures could be evaluated.
2. Prepare overarching cumulative estimate of the air quality effects from implementation of all the Task Force recommended mitigation measures.
3. Describe a "gold standard" for the best technical analyses that can be done, and provide recommendations for future analyses. Describe the uncertainty associated with the air quality estimates.
4. Respond to issues referred to the CE work group from other work groups.
5. Recommend additional analysis, studies, etc. that may be necessary for the CE work group to fully carry out its tasks. For example, the CE may feel that it is necessary to conduct an ozone precursor field study with advice from the monitoring group, or an ammonium field study for particulate matter.

Discussion

In accomplishing #1, the Cumulative Effects work group was charged with assessing upwards of 20 of the numerous mitigation options being proposed by the source-related work groups. For these options, the emissions reductions associated with undertaking the mitigation approach have been estimated. In addition, the work group also detailed methods, assumptions, limitations, and sources of information.

All of the tasks associated with estimating emissions reductions were relative to the oil and gas sector. In order to make much of this work as accurate as possible, the Cumulative Effects work group undertook improvements to the base case inventory for drilling and production activities in the Four Corners region. The base case inventory shows what current and future emissions would be in the absence of additional air pollution mitigation. The best data from the Western Regional Air Partnership (WRAP), the States of New Mexico and Colorado, the Southern Ute Indian Tribe, and industry participants were consolidated and quality assured to create a more accurate and complete inventory than previously existed. Using estimates of the effectiveness of the various mitigation options and applying them to the base case, estimates of the number of tons of pollution that would be reduced by each mitigation option were calculated. Emissions reductions associated with mitigation options directed and motor vehicles used in oil and gas activities were also estimated.

Because of the length of time and resources required to set up modeling analyses and to accomplish them, the modeling task (#2) was moved outside the Task Force process. It will inform regulatory agencies of the air quality benefits of options after the Task Force report is completed. The approach taken is akin to the "gold standard," and thus #3 was addressed as part of the agencies' modeling effort.

Consistent with #4, the Cumulative Effects work group also responded to requests for additional information relative to a few of mitigation options, for example, answering questions about monitoring at a power plant and providing a bit more detailed description of overall emissions.

Related to #5, suggestions for future research associated with implementation of the mitigation options are presented, for example, with regard to the sources and impacts of ammonia emissions and the economic effect of various mitigation option

OVERVIEW OF WORK PERFORMED

The Cumulative Effects (CE) work group was requested to provide information on a number of mitigation options described by the source work groups. Table 1 summarizes the reasons why the Cumulative Effects work group may or may not have researched a particular question, and a brief description of the outcome if work was performed.

Table 1: Summary of mitigation option findings.

OPTION	ACTION TAKEN BY CE	SUMMARY OF RESULT
Tax or Economic Incentives for Environmental Mitigation	CE did not have expertise to address this option.	No action.
Selective Catalytic Reduction (SCR) on Drilling Rig Engines	There was insufficient time to address this option.	Some data exists on drilling emissions. The State of Wyoming evaluated this technology based on a pilot study in the Jonah Field & concluded that is not a cost effective technology, but further analysis is needed.[1]
Implementation of EPA's Non Road Diesel Engine Rule – Tier 2 through Tier 4 Standards for Drilling Rigs	There was insufficient time to address this topic.	An important piece of information is that these engines typically last 4-10 years and then need to be replaced. This means that there will be a constant infusion of new technology engines over time. However, faster turnover would reduce emissions in the near-term.
Industry Collaboration for RICE	This option was not evaluated because it is not possible to quantify emission reductions.	No action.
Install Electric Compression for RICE	This option was evaluated.	Replacement of low emission engines with electric power grid would result in an overall increase in emissions. A reduction in NOx emissions would occur, however, there would be an increase greenhouse gas emissions due to increased electrical generation requirements.
Follow EPA Proposed New Source Performance Standards (NSPS) for RICE	This option was evaluated.	This proposed emission standard will become the baseline for new modified and reconstructed engines. Future year projections indicate that these standards will minimize growth in oil and gas emissions from natural gas fired engines.
Install Selective Catalytic Reduction (SCR) on Lean Burn Engines for RICE	This option was evaluated.	There is very little information on the installation of this control technology on natural gas fired engines. What is available indicates that in the Four Corners area the installation of this technology would result in small NOx reductions. In addition, the cost to control emissions would be relatively high.[2] **Differing Opinion:** Disagree with the last two sentences.
Install Non Selective Catalytic Reduction (NSCR) on Rich Burn Engines for RICE	This option was evaluated.	It was found that installation of NSCR on small engines could reduce NOx emissions significantly. The USEPA performance standard for rich burn engines will likely require installation of NSCR for new, modified and reconstructed rich burn engines.

OPTION	ACTION TAKEN BY CE	SUMMARY OF RESULT
Install Lean Burn Engines for RICE	This option was evaluated.	Emission inventory data indicated that on large engines of greater than 500 horsepower this technology or NSCR is already being used on the majority of the engines in the region. The use of these engines results in significant reductions in NOx over the use of rich burn engines, and may be beneficial when applied to smaller engines.
Install Selective Non Catalytic Reduction (SNCR) for RICE	This option was evaluated.	It was determined that this technology is unlikely to be used because it is less effective than SCR or NSCR.
Install Oxidation Catalyst on Lean Burn Engines for RICE	This option was evaluated.	This mitigation option was evaluated in terms of HAPs emissions and VOCs. Previous modeling analyses indicated that HAPs impacts are localized. It was found that VOC emission reductions would be primarily methane and ethane which have a low photochemical reactivity, and likely do not contribute to ozone formation. **Differing opinion:** Contest the previous statement as to accuracy. Methane is a greenhouse gas and reduction of methane emissions is desirable in combating global climate change.
Install Optimized/Centralized Compression	This option was evaluated.	It was concluded that there would be no opportunities for reducing emissions as a result of implementing this option.
Next Generation Control Technology for RICE	This option was evaluated.	Because these technologies are emerging, it is not possible to quantify the additional benefits of controls.
Automation of Wells to Reduce Truck Traffic	This option was evaluated.	Potential fugitive dust emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.
Centralized Produced Water	This option was evaluated.	Potential fugitive emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.
Efficient Routing of Water Trucks	This option was evaluated.	Potential fugitive emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.
Cover Lease Roads with Rock or Gravel	This option was evaluated.	Potential fugitive emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.
Enforcing Speed Limits on Dirt Roads	This option was evaluated.	Potential fugitive emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.

OPTION	ACTION TAKEN BY CE	SUMMARY OF RESULT
Selective Catalytic Reduction (SCR) NOx Control Retrofit	This option was not evaluated.	Only emission reductions were estimated, not effects on visibility or ozone, so could be done as a part of future work.
Emissions Monitoring for Proposed desert Rock Energy Facility to be Used Over Time	This option was assessed.	The option was looked at by the CE Work Group, and an assessment included.
Declining Cap and Trade Program for NOx Emissions for Existing and Proposed Power Plants	This option was not evaluated.	Only emission reductions were estimated, not effects on visibility or ozone, so could be done as a part of future work.
Chronic Respiratory Disease Study for the Four Corners Area	A brief look at the data was done.	A summary of ozone trends generally showed an upward trend. Another look at this question will be provided by future work.
Install Electric Compression	This option was evaluated.	See above.

Emissions Summary

The overall emissions of nitrogen oxides (NOx) and volatile organic compounds (VOC) broken into broad source categories can provide some perspective when reductions from various mitigation options are presented in subsequent sections. Table 2 shows the relative importance of groups of sources in the Four Corners region:

Table 2: Percentage of total future year emissions in 2018 by pollutant.

SOURCES	NOx EMISSIONS (%)	VOC EMISSIONS (%)
Mobile	2	5
Area	1	23
Oil & Gas	26	32
Power Plants	40	1
Other Point Sources	30	39

This table demonstrates that oil and gas production, electrical generation, and other industrial activities are the largest emitters of nitrogen oxides, while oil and gas production, industrial facilities other than those related to power plants and oil and gas production, and area sources emit the majority of VOC. Area sources are those industrial and commercial activities that are small enough to not be required to obtain an air quality permit to operate. Area sources also include a broad range of human activities that result in small amounts of pollution on an individual basis.

The data presented in Table 1 have been derived primarily from the Western Regional Air Partnership (WRAP) emission inventory. For these categories, the Four Corners Air Quality Task Force requested an extraction from the WRAP regional database for the Four Corners area that encompasses portions of Colorado, New Mexico, Arizona, and Utah. The one exception is for oil and gas sources, which were estimated using updated information developed by the Cumulative Effects work group.

Emissions Reduction Summary

Table 3 summarizes emission reductions for mitigation options for which the estimates were made in order to facilitate comparison. Some estimates were made by the Cumulative Effects work group for the Oil and Gas work group, while some were made by the Power Plants (PP) work group for their own options. Descriptions of the mitigation options and how the estimates were derived can be found in the section of each work group, respectively.

Table 3: Mitigation Option Summary

Mitigation Option	Work Performed By	Pollutant Reduced	Reduction Estimate (tpy)
Control Technology Options for Four Corners Power Plant	PP	NOx	11,688
Control Technology Option for San Juan Generating Sta.	PP	NOx	6,166
Enhanced SO2 Scrubbing	PP	SO2	2,083
Selective Catalytic Reduction (SCR) NOx Control Retrofit	PP	NOx	29,987 to 46,684
BOC LoTOx System for Control of NOx Emissions	PP	NOx	43,257
Baghouse Particulate Control Benefit	PP	PM10	465
Declining Cap and Trade Program for NOx Emissions	PP	NOx	3,428
Install Electric Compression w/ Grid Power	CE	NOX & SO2	Variable – See note below
Install Electric Compression w/ Onsite Gen Power	CE	NOX & SO2	12,000 to 40,721
Use of NSCR for NOx Control on Rich Burn Engines	CE	NOx	16,588 to 21,327
Use of SCR for NOx Control on Lean Burn Engines	CE	NOx	Insufficient information to quantify
NSPS Regulations	CE	NOx	0
Optimization/Centralization	CE	NOx	0
Use of Oxidation Catalyst for Formaldehyde & VOC Control on Lean Burn Engines	CE	VOC	1619
Automation of Wells to Reduce Truck Traffic	CE	PM10 & NOx	196 & 92
Reduced Truck Traffic by Centralizing Produced Water Storage	CE	PM10	39
Reduced Truck Traffic by Efficiently Routing Produced Water Disposal Trucks	CE	PM10	196
Reduced Vehicular Dust Protection by Covering Lease Roads with Rock or Gravel	CE	PM10	206
Reduced Vehicular Dust Production by Enforcing Speed Limits	CE	PM10	73

Note: Some engine configurations are as efficient as current coal-fired generating stations without being subject to line losses, whereas other engines would be less efficient than using commercially available line power.

Suggestions for Future Work

As the Cumulative Effects work group completed the tasks of evaluating mitigation options, it became clear that there is a need for future work to provide regulatory agencies additional information on the benefits of reducing pollution emissions into the air in the Four Corners region. Additional detailed modeling is planned by the agencies that will provide more refined information regarding the actual effects of proposed mitigation programs. The modeling analysis is scheduled for completion in the fall of 2007. Leading into the analysis of mitigation programs, some updating of source information will be necessary. An example would be for drilling rigs.

To supplement the modeling analyses, additional monitoring of pollutants and meteorology throughout the Four Corners region would be useful. This monitoring would provide a basis for establishing whether model predictions are accurate and would help determine air quality trends. Currently, there are relatively few air monitoring sites in the Four Corners region to use in testing model performance. Monitoring for ammonia would be particularly useful as it enhances the ability of the model to estimate the effects of air pollutant emissions on visibility.

The Cumulative Effects work group was required to delve into agency emissions inventories in detail, and this work exposed many weaknesses in state and tribal inventories. For future analysis of options, it is recommended that states and tribes require more robust reporting of industrial entities, including reporting of facilities that may currently fall below permitting or reporting thresholds. States and tribes may require regulatory changes to reporting requirements to accomplish this. Lack of detailed reported data introduces a high level of uncertainty into analysis of options for mitigation. State and tribal agencies need to be able to quantify cumulative reductions with certainty in order to appropriately evaluate and prioritize options. By performing analyses that combine trends in emissions with trends in monitoring data, information may be identified regarding source receptor relationships.

The work group also recommends a review of existing field test data and an expansion of the existing state and tribal field testing programs for source emissions. Improvement of inventory emissions estimates will result in better modeled estimates of air pollution concentrations. A focused effort to obtain and share emissions data from a variety of oil and gas engines under different operating conditions would be particularly beneficial in inventory improvement.

Finally, the work group recommends that economic analysis of options be conducted to provide cost/benefit information to state and tribal agencies. The work group did not have the time or resources to conduct economic modeling, but economic data is of great importance in analyzing and prioritizing options. Such modeling could analyze "bundled" options to minimize analysis costs.

Endnotes:

1 Personal communication between Reid Smith (BP) and David Finley (WDEQ).

2 EPA Speciate data for natural gas-fired engines.

DETAILED DESCRIPTIONS OF MITIGATION OPTION ANALYSES

Mitigation Option: Install Electric Compression with Grid Power

Description of Option

Under this option, existing or new natural gas fired internal combustion engines would be replaced with electric motors for powering compressors. Electric motors would be selected to deliver equal horsepower to that of the internal combustion engines being replaced.

Assumptions

It is assumed that electricity to power the electric motors would come from the existing electrical grid. The majority of the base load electricity in the region is produced from coal-fired electrical generation.

This option did not consider the installation of natural gas electrical generation systems, which would have entirely different emissions characteristics from coal-fired electrical generation. In this approach, small high-emission natural-gas engines would be replaced by electric motors driven by a larger low-emission natural-gas engine. Although natural gas fired generators have not been used in the region, the feasibility for possible future use should be investigated. [1]

In evaluating the changes in emissions for shifting from natural gas to electric (coal) powered compression, it is necessary to examine the emissions for each power source on an equivalent energy basis. Thus, for the same amount of energy consumption, the change in emissions from natural gas versus electricity must be considered.

In the evaluation of this mitigation option, it is not appropriate to consider emission modifications to existing electrical generating facilities. While such modifications may occur or new lower emitting facilities may be developed, the inclusion of such changes in emissions are speculative at this point in time. The emission data was developed using the EPA program EGRID. [2]

In this analysis, it was assumed that for visibility SO_2 and NO_x emissions are equivalent in terms of impacts because they cause approximately the same amount of visibility impairment. This is because the dry scattering coefficients for converting SO_4 and NO_3 concentrations into visual range are approximately equivalent. NO_x emissions do participate in photochemical reactions that produce ozone.

However, ozone modeling analyses performed by the state of New Mexico as part of the Early Action Compact (EAC) and ozone monitoring data in the area suggest that ozone formation is VOC limited and consequently NO_x emission reductions may cause increases in ozone concentrations. Both SO_2 and NO_2 ambient concentrations are in compliance with federal and state air quality standards.

As a first order approximation, 1 ton per year of SO_2 emissions will result in the same amount of potential visibility impairment as 1 ton per year of NO_x. In reality, because of the more complex and competitive reactions involving both SO_4 and NO_3, SO_2 emissions may result in more visibility impairment than NO_x emissions.

From an economic basis, conversion of natural gas-fired engines to electric compression is only practical for large engines and only in areas where electricity is already available within close proximity. This is because most locations do not currently have electrical power and it would not be cost effective to install power for small engines.[3]

In Colorado, most large engines (greater than 500 hp) are lean burn or have NSCR installed to reduce emissions (average emission factor for this size engine is 1.4 g/hp-hr). In addition, any new engines in this size category must achieve an emission limit of 1 g/hp-hr.[4] These engines are typically located at remote sites where power is not available.

In New Mexico, for large engines (greater than 500 hp) the average emission factor is 3.0 g/hp-hr. There are a total of 354 engines in this size category.[5] Of that total, 221 engines have NOx emission less than or equal to 1.5 g/hp-hr (62 percent), 108 engines have NOx emissions in the range of 1.6 to 5 g/hp-hr (31 percent) and 25 engines have NOx emissions greater than 5 g/hp-hr (7 percent). Under a recent BLM EIS Record of Decision (ROD), new engines must achieve 2 g/hp-hr.

Method

The energy consumption of a typical lean burn engine was calculated, converted into pounds per mega watt-hour and was compared to SO2 and NOx emissions from existing coal-fired power plants. This was done assuming an emission factor between 1 g/hp-hr and 5 g/hp-hr. It was then assumed that the computed emissions per mega watt of power represented emissions for 1-hour and were converted into tons per year by multiplying by 8760 hours per year and dividing by 2000 pounds per ton.

As indicated in Table 4, a shift from natural gas to electric (coal) for an engine of 1 MWhr capacity (approximately 1,342) hp with an emission factor of 1 g/hp-hr would result in an **increase** of 14 tons per year of SO2 + NOx. With engine emissions of approximately 2.0 g/hp-hr there is no net change in overall emissions by shifting from natural gas to electric. For all cases, the shift from natural gas to electricity results in higher greenhouse gas emissions.

Conclusions

NOx emissions from large engines in Colorado and the remaining engines in New Mexico are currently controlled at sufficient levels so that shifting from natural gas to electric compression may only result in a small reduction in emissions and in many cases would result in an increase in SO2 and NOx emissions.

For all categories of engines, greenhouse emissions would increase by shifting compressors from natural gas to electric.

Table 4: Change in SO2, NOx and Greenhouse Gas Emissions by Shifting from Natural Gas Compression to Electricity

Four Corners Grid Average Emissions lbs/MWh		tons/MWh/yr
SO2	**2.65**	**11.6**
NOx	**3.64**	**15.9**
NOx + SO2	**6.29**	**27.6**
CO2	**1,989**	**8711.8**

Table 4A: Example Engine Changes

Caterpillar 3608 LE Average Emissions lbs/MWh (equivalent)		Other Emission Rates (gr/hp-hr)				
SO2	0	0	0	0	0	0
Hp/kw-hr	1.342	1.342	1.342	1.342	1.342	1.342
Hp/mw-hr	1,342	1,342	1,342	1,342	1,342	1,342
Cubic feet gas/mw-hr	9,815	9,815	9,815	9,815	9,815	9,815
NOx Emission Rate gr/hp-hr	1	2	3	4	5	16
SO2 lbs/mw-hr	0	0	0	0	0	0
NOx lbs/mw-hr	3.0	5.9	8.9	11.8	14.8	47.3
CO2 lbs/mw-hr	1,138	1,138	1,138	1,138	1,138	1,138
SO2 tons/MWh/yr	0.0	0.0	0.0	0.0	0.0	0.0
NOx tons/MWh/yr	13.0	25.9	38.9	51.8	64.8	207.4
CO2 tons/MWh/yr	4985	4985	4985	4985	4985	4985
Delta SO2 tons/Mwh/yr	11.6	11.6	11.6	11.6	11.6	11.6
Delta NOx tons/Mwh/yr	3.0	-10.0	-22.9	-35.9	-48.9	-191.4
Delta NOx +SO2 tons/MWh/yr	14.6	1.6	-11.3	-24.3	-37.3	-179.8
Delta CO2 tons/Mwh/yr	3727	3727	3727	3727	3727	3727
Cat. 3608 Assumptions: 9815 Btu/kw-hr "Sweet" Natural Gas NOx - 1 gr/hp-hr 1 cu ft gas = 1,000 btu						

Endnotes:

1 Factors that need to be considered for use of a natural gas fired electrical generation system are: engines must be located in clusters that lend themselves to being interconnected by power lines; generator and line reliability need to be evaluated; the efficiency of electrical generators systems compared to natural gas fired compression must be evaluated; it needs to be determined if natural gas fired electrical

generators have substantially lower emissions than new natural gas fired compressor engines; cost and the benefits of this analysis need to be evaluated in terms of potential ambient air quality benefits, not simply emission reductions.

[2] EPA EGRID Program http://www.epa.gov/cleanenergy/egrid/index.htm

[3] The quantification of changes in emissions of this option does not address the cost of implementation or the reliability of the electrical grid. These issues must be considered if this option is deemed beneficial from an environmental perspective.

[4] Northern San Juan EIS Record of Decision (April 2007)

[5] NMED Part 70 permits, Minor source permits and Environ inventory.

Mitigation Option Analyses: Replace RICE Engines with Electric Motors for Selected Oil and Gas Operations (Alternative 2 – Power Source: On-Site Natural Gas-Fired Generators)

Description of Analysis of the Alternative Option

As an alternative to grid power, dedicated on-site, natural gas-fired, electrical generators can be used to supply power to electric motors suitable for selected replacement of "dirty" compression and other E&P RICE engines. This alternative to the Install Electric Compression (Grid Power Alternative) expands candidate engines for replacement beyond compressor engines since some existing compressor engines, particularly in the Northern San Juan Basin, are already well controlled. The electric motors are rated on an equivalent horsepower basis to RICE engines targeted for replacement. This analysis covers both the top 25 "dirtiest" and all essentially uncontrolled, primarily small, rich burn engines, with emissions greater than 4 g/hp-hr. Net NOx and CO emission reductions are reported in mass emission rates (tons/yr) and normalized mass emission rates (tons/yr/MW).

Assumption

The currently available gas electric generators run on variety of fuels including low fuel landfill gas or bio-gas, pipeline natural gas and field gas. The gas electric generators are available in the power rating from 11 kW to 4,900 kW. The calculated net reduction in emissions from existing RICE engines to electric motors powered by on-site electric generators were done based on an equivalent power basis.

In order to implement this option an electrical infrastructure would need to be constructed between the locations of the gas fired generator and the electric compressors. In addition, a control system would have to be developed so that as the engine load (demand) varies the generator supply would be adjusted to meet the demand. In order to implement this option it may be necessary to connect the generator to the power grid so that excess electricity could be utilized. Several engine companies manufacture gas electric generators. We assumed use of a mid-size Caterpillar gas electric generator as the reference natural gas on-site generator for calculating the net emissions for this alternative (not to be construed as an endorsement). The Caterpillar G3612 gas electric generator with power rating of 2275 kW emits 0.7 gram/hp-hr NOx and 2.5 g/hp-hr CO. It is important to note that the emissions from such generators are not different than what can be achieved from a lean burn engine (available with a capacity in excess of 500 hp) and not appreciable different emissions from new NSPS engines.(2 g/hp-hr vs 0.75g/hp-hr).

The selection of RICE engines for electrification analysis did not consider important factors that would need to be weighed in determining the degree of implementation that might be feasible. This would include the locations and spatial distribution of engines (e.g., proximity of with each other), the number and cost of required on-site generators, maximum transmission line lengths and any ROW issues, number of electric motors and costs, and operational and environmental factors.

Available engine inventories, for producers in New Mexico and Colorado (e.g., bp) were combined in order to obtain a representative engine inventory for the San Juan Basin.

Method

The NOx and CO emission of the reference Caterpillar G3612 generator were given in g/hp-hr which was converted into lbs/MW-hr by multiplying the (1,342 hp/MW) and divided by (454 gm/lbs). Further, the NOx and CO emissions in tons/yr/MW units were obtained by multiplying 8760 hrs/yr and dividing by 2000 lbs/ton. The NOx and CO emission factors and calculated normalized emission rates for NG generator are given in Table 5.

Table 5: Gas Electric Generator Emissions

2,275 kW			
	(g/hp-hr)	(lbs/MWh)	(tons/yr/MW)
NOx	0.70	2.07	9.06
CO	2.50	7.39	32.37

The net emission reduction was first calculated for the replacement the 25 worst NOx emitters and compared with a greater subset of replaced engines (e.g., engines emitting more than 4 g/hp-hr engines). The selection of the 25 worst engines is based on potential tons/yr NOx emission of individual engines. The potential engine emission calculation assumes 100% load and 8760 hrs operation per year. Engine emission factors were obtained by combining the New Mexico and Colorado engine inventory database used the Alternative 1 analysis.

The following illustrates how the mass emission rates (ER) and normalized mass emission rates (NER) were calculated for each engine size group.

EF (24.6 g/hp-hr) * Engine Size (1,350 hp) * (# of engines) * (8,760 hrs/yr) * (1/454g/lbs) * (1/2,000 lbs/ton) = 320.4 (tons/yr)

EF (24.6 g/hp-hr) * (1,342 hp/MW) * (8,760 hrs/yr)*(1/454g/lbs)*(1/2,000 lbs/ton) = 318.5 (tons/yr/MW)

The 25 engines with the highest mass emission rates in the combined inventory were identified. The total power of these was obtained by adding the rated power of individual engines, which was used to calculate equivalent emission from gas generator needed to run the 25 electric motors replacing the replaced RICE engines. For the case of the 25 highest emitting engines, the average capacity is 684 hp, the maximum capacity is 2,400 hp and the lowest capacity is 325 hp. What is important about the capacities is that for the majority of these engines lean burn engines are available. Table 6 shows the normalized average emissions in tons/yr/MW as well as net potential mass emission reductions for both NOx and CO emission based on the 25 worst NOx emitters. The average emission factor for the top 25 engines is 23.9 g/hp-hr.

Table 6: Emission change if 25 worst NOx emitting engines retired

Total rated power = 17,108 hp = 12.8 MW		
	NOx	
	Avg. NER (tons/yr/MW)	Total ER (tons/yr)
Caterpillar G3612	+9.06	+115.51
Worst 25 Engines	-251.21	-3,106.40
Net Reduction	-242.14	-2,990.89

Table 7 shows the same calculations based on all the engines emitting more than 9 g/hp-hr.

Table 7: Emission change if all engines emitting > 4g/hp-hr NOx retired

2925 engines with total rated power = 233,278 hp = 205.7 MW Emitting > 9 g/hp-hr NOx		
	NOx	
	avg/engine (tons/yr/MW)	Total (tons/yr)
Caterpillar G3612	9.06	1,863.75
All engines emitting more than 4.0g/hp-hr	211.36	40,562.21
Net Reduction	-202.30	-38,698.45

Conclusion

A net reduction of approximately 2,991 tons/yr of NOx can be achieved if the 25 engines with the highest NOx mass emission rate t operating in the San Juan Basin are replaced with nine 2 MW well controlled on-site natural gas electrical generators. Although most large RICE engines operating in the San Juan Basin are relatively small emitters individually and collectively, a significant number of small and medium range engines are not controlled well and collectively represent a relatively large E &P emission source group. The analysis in this alternative reveals a potentially significant emission reductions are possible for this group of engines. The calculation of emission reduction for replacing all the engines emitting more than 9.0 g/hp-hr NOx (over 2925 engines) with electric motors powered by several similar natural gas generators show that 38,698 tons/ per year of NOx reduction might be achieved by this option. This level of replacement would require approximately 90 on-site generators rated at 2 MW.

The potential emission reductions presented in this analysis assume optimal mitigation option implementation conditions which may not be nearly as optimistic if more detailed data were available and factored into the analysis. The selection of engines for electrification analysis did not consider important factors that would need to be weighed in determining the option feasibility and what degree of implementation would be possible. Factors such as the locations and spatial distribution of engines and operational and environmental issues would need to be considered. These and other factors would need to be carefully evaluated to better quantify the effectiveness of this alternative in terms of potential emission reductions achievable and certainly in quantifying implementation costs.

References

1. The emission and power information for the Caterpillar G3612 Gas Generator was obtained from Caterpillar's website. www.cat.com.

2. The engine inventory for NM and CO used to calculate emission reduction was provided by BP America, which includes contributions from: BP, New Mexico Environment Department, Colorado Dept. of Public Health & Environment and ENVIRON

Mitigation Option: Use of NSCR for NOx Control on Rich Burn Engines

Description of the Option

NO_X, CO, HC, and formaldehyde emissions from a stoichiometric engine can be reduced by chemically converting these pollutants into nitrogen, carbon dioxide and water vapor. The most common method for achieving this is through the use of a catalytic converter. In a catalytic converter, the catalyst will either oxidize (oxidation catalyst) a CO or fuel molecule or reduce (reduction catalyst) a NO_X molecule.

A process which causes reaction of several pollutant components is referred to as a Non Selective Catalyst Reduction (NSCR) and is applicable only to stoichiometric engines. Engines must operate in a very narrow air/fuel ratio (AFR) operating range in order to maintain the catalyst efficiency. Maintaining low emissions in a stoichiometric combustion engine using exhaust gas treatment requires a very closely regulated air/fuel ratio. Without an AFR controller, emission reduction efficiencies will vary. Most AFR controllers utilize closed loop control based on the readings of an exhaust gas oxygen sensor to determine the air/fuel ratio.

An AFR controller will only maintain an operator determined set point. For this set point to be at the lowest possible emission setting, an exhaust gas analyzer must be utilized and frequently checked.

Some issues associated with current practice NSCR retrofits on existing small engines operating at reduced loads are:

- a problem maintaining sufficient flue gas inlet temperature for correct oxygen sensor operation and the resulting effectiveness of the catalysts
- On engines with carburetors, there is difficulty maintaining the AFR at a proper setting
- On older engines, the linkage and fuel control may not provide an accurate enough air/ fuel mixture
- If the AFR drifts low (i.e., richer), ammonia formation will increase in proportion to the NOx reduction but not necessarily in equal amounts.

The first issue can be mitigated by retarding the ignition timing when the engine operates at reduced loads. The retarded ignition timing reduces NOx emissions and also raises the flue inlet temperature which helps maintain the catalyst efficiency. Eliminating or mitigating the second, third, and fourth issues require a closed-loop feedback control with an exhaust oxygen sensor to continuously adjust the AFR. One way of doing this is to adjust the carburetor so it operates slightly lean and use the feedback control to adjust the amount of supplemental fuel supplied to a port downstream of the carburetor. Worn carburetors and linkages should be replaced as a maintenance issue.

Assumptions

Currently, recent EIS RODs in Colorado and New Mexico require performance standards for new or replacement engines that will accelerate the implementation of the 2008 and 2010 federal NSPS for non road engines. Most engines in the 4 Corners Region in excess of 500 hp are lean burn engines and that trend is expected to continue in the future. These engines meet low emission standards through lean burn combustion technology and NSCR catalyst cannot be installed on this type of source. Therefore, the implementation of NSCR technology would have little or no effect on emission levels for new or replacement engines in excess of 500 hp. New or replacement engines having capacities of less than 500 hp and 300 hp will be required to meet an emission limit of 2 g/hp-hr in Colorado and New Mexico, respectively. Because of the limited availability of lean burn engines in this size range, NSCR will have to be used to achieve the prescribed emission levels. Thus, it is very likely that new or replacement engines will use this technology and there will be no additional possible NOx emissions reductions. It is important to note that a properly designed and operated NSCR system can achieve emission levels less than 2 g/hp-hr. However, the question becomes one of maintaining emissions at lower levels on a continuous basis and the operator's need to have a safety factor for ensuring continuous compliance with source emission limits. Thus, on average, actual emissions will be less than the prescribed regulatory limits, however, there will be times when emissions will approach the regulatory limit.

In examining additional NOx mitigation (beyond current regulatory drivers), NSCR would be applicable to existing rich burn engines that have a capacity of less than 500 hp.

In order for NSCR technology to result in any reduction of NOx emissions in the 4 Corners Region, it would have to be implemented on existing engines less than 500 hp. Estimates of potential emission reductions were calculated for engines in the range of 300 to 500 hp, 100 to 300 hp and between 75 hp and100 hp. Currently, there is no single retrofit kit that can be installed on existing engines. Even if an air fuel ratio controller with an oxygen sensor were installed, it is uncertain if the carburetor linkage would allow an accurate and precise enough control required to maintain the proper air fuel mixture without repair or upgrade.

However, compliance data (unannounced tests) obtained from the SCAQMD for 215 retrofitted rich burn engines show that over 90% of these engines, with installed AFRC, were able to meet or do better than 2 g/hp-hr. Six engines were essentially uncontrolled due to lack of any installed AFRC. Over 77% of the tested engines did better than 1 g/hp-hr (SCAQMD, 2007).

Engine Size >300 hp and < 500 hp

The uncontrolled NOx emission factor for existing rich burn engines between 300 hp to 500 hp in Colorado and New Mexico ranges from 11.4 to 21 g/hp-hr. The average emissions from the 11 rich burn engines in this size group are 18.3 g/hp-hr. The mass emission rate of a combined 3,660 hp for these engines total nearly 650 tons NOx/yr. Many of the engines in the 300-500 hp range already had some emission controls on them (such as being lean burn).

In new applications, laboratory data shows that NSCR can exceed 90% NOx reduction and in some cases possibly 95%. Because mitigation is being considered on a fleet of older existing engines, it may not be possible to achieve a 90% plus level of performance reliably in the field. Field tests to address this and other issues are being planned by Kansas State and are expected to start soon. Based on what we know now, lab data and existing compliance data from an inventory of over 200 retrofitted operating engines in southern CA., it was assumed that a well designed NSCR retrofit kit could reliably achieve NOx reduction in the range of 70% to 90%, Applying NSCR retrofits on the identified 11 "dirty engines" could reduce the NOx emissions to 1.8 tg/hp-hr (an ~ 450 tons/yr reduction) at the low end and 5.5 g/hp-hr at the high end (an ~ 590 ton/y reduction).

Engine Size > 100 hp < 300 hp

The uncontrolled NOx emission factor for existing rich burn engines between 100 hp to 300 hp in Colorado and New Mexico ranges from 15 to 24 g/hp-hr. The average emissions from the 240 rich burn engines in this size group are 19.1 g/hp-hr. The mass emission rate of the combined 38,394 hp for these engines total over 7,000 tons NOx/yr. Some engines in this size range were excluded from this group because they were identified as lean burn

Based on what we know now, lab data and existing compliance data from an inventory of over 200 retrofitted operating engines in southern CA, it was assumed that a well designed NSCR retrofit kit could reliably achieve NOx reduction in the range of 70% to 90%, Applying NSCR retrofits on the 240 identified "dirty engines" could reduce the NOx emissions to 1.9 g/hp-hr (an ~ 6,500 tons/yr reduction) at the low end and 5.7 g/hp-hr at the high end (an ~ 5,000 ton/y reduction). Not all retrofits may be operationally practical or economically feasible.

Engine Size > 75 hp and < 100 hp
The uncontrolled NOx emission factor for existing rich burn engines between 75 hp to 100 hp in Colorado and New Mexico ranges from 9.4 to 22.4 g/hp-hr. The average emissions from the 901 rich burn engines in this size group are 19.7 g/hp-hr. The mass emission rate of the combined 84,307 hp for these engines total over 11,200 tons NOx/yr. The lowest emitters are a group of Ford engines that may have EGR, but the database does not specify whether they have EGR.

Based on what we know now, lab data and existing compliance data from an inventory of over 200 retrofitted operating engines in southern CA, it was assumed that a well designed NSCR retrofit kit could reliably achieve NOx reduction in the range of 70% to 90%, Applying NSCR retrofits on the 900 identified "dirty engines" could reduce the NOx emissions to 5.9 g/hp-hr (an ~ 11,200 tons/yr reduction) at the low end and 2.0 g/hp-hr at the high end (an ~ 14,400 ton/y reduction). Not all retrofits may be operationally practical or economically feasible.

There is considerable uncertainty in the NOx reduction in these engines, which tend to be older than the engines in other size ranges. Attention to worn linkages and carburetor parts as well as closed-loop AFR control is expected to be necessary if these engines are to achieve effective NOx reduction.

Additional long term testing of the use of NSCR on existing small engines must be performed prior to any large scale implementation of this option. Currently, testing is beginning that will address the field application of this technology for retrofit conditions on rich burn small engines..[1]

<u>Method</u>
A spreadsheet containing the combined engine inventories for Colorado and New Mexico was developed. For each of the three size ranges of interest, a new database was created in which engines outside the size range of interest were deleted. Each of the three newly created databases were further modified by deleting all engines that are identified by their model designation as "lean-burn" and by deleting all remaining engines whose NOx emissions are 5.0 g/hp-hr or less. The resulting three databases contain only rich-burn engines in the size ranges of interest. Overall NOx emissions were totaled for each of the three size ranges, and emissions reductions of 70% and 90% were applied. resulted in a reduction in NOx emissions of 723 tons per year (a 7 percent reduction of Colorado oil and gas emissions). The engines in the New Mexico inventory were treated similarly.

One important point is that the New Mexico inventory indicated that 1,024 engines were less than 40 hp, which is the proposed de minimus threshold in the NSPS. Under the proposed regulation, EPA concluded that control of this size engine is not appropriate or cost effective. In New Mexico this class of engines had emissions of 2,049 tons per year (i.e., each engine had emissions of approximately 2 tons per year).

Table 8 presents the projected changes in NOx emissions if NSCR were installed on existing engines in Colorado and New Mexico.

Table 8: Emission Reductions from implementing NSCR on Existing Rich Burn Engines in Colorado and New Mexico

Colorado and New Mexico, 70% Reduction - NSCR on all Existing Rich-Burn Engines

Engine Size	Reduction (%)	Average Mitigated Emission Factor (g/hp-hr)	Unmitigated Total (16-year 2018-year) Average NOx Emissions (t/yr)	NOx Reduction (t/yr)
< 500 hp Eng > 300 hp	70	5.5	3150	453
< 300 hp Eng > 100 hp	70	5.7	5948	4934
< 100 hp Eng > 75 hp	70	5.9	13317	11201
Total Reduction			**51783**	**16588**
Percent Reduction				**32**

Colorado and New Mexico, 90% Reduction – NSCR on all Existing Rich-Burn Engines

Engine Size	Reduction (%)	Mitigated Emission Factor (g/hp-hr)	Unmitigated Total (16-year 2018-year) Average NOx Emissions (t/yr)	NOx Reduction (t/yr)
< 500 hp Eng > 300 hp	90	1.8	3150	582
< 300 hp Eng > 100 hp	90	1.9	5948	6343
< 100 hp Eng > 75 hp	90	2.0	13317	14402
Total Reduction			**51783**	**21327**
Percent Reduction				**41**

Conclusions

Installing NSCR on existing engines less than 500 hp in Colorado and New Mexico would result in a reduction of approximately 16,588–21,327 tons per year of NOx over current projected emissions in 2018.

Additional field testing on the installation of retrofit NSCR on engines less than 500 hp is needed to document what level of emission control could be achieved on a continuous basis.

Detailed modeling is planned that will quantify the air quality benefit of such reductions either separately or in combination with other potential mitigation measures. For visibility, currently in the Mesa Verde and Wimenuche Class I Areas NOx emissions are a very small portion of the total extinction budget, however in recent years the trend has been flat or showed slight increases. Also, because of complex photochemical reactions involving VOC emissions and NOx emissions, changes in NOx emissions could result in localized increases or decreases in ozone. Regional effects of changes in ozone precursor emissions would need to be determined using a photochemical model.

Mitigation Option: Use of SCR for NOx Control on Lean Burn Engines

<u>Description of the Option</u>

Using this option, existing or new lean burn natural gas fired internal combustion engines would be installed with selective catalytic reduction (SCR). This technology uses excess oxygen in a selective catalytic reduction system. Reactant injection of industrial grade urea, anhydrous ammonia, or aqueous ammonia is required to facilitate the chemical conversion. A programmable logic controller (PLC) based control software for engine mapping/reactant injection requirements is used to control the SCR system. Sampling cells are used to determine the amount of ammonia injected which depends on the amount of NO measured downstream of the catalyst bed.

In the proposed standards for Stationary Spark Ignition Internal Combustion Engines, EPA states the following with respect to the installation of SCR on natural gas fired engines: "For SI lean burn engines, EPA considered SCR. The technology is effective in reducing NOx emissions as well as other pollutant emissions, if an oxidation catalyst is included. However, the technology has not been widely applied to stationary SI engines and has mostly been used with diesel engines and larger applications thousands of HP in size. This technology requires a significant understanding of its operation and maintenance requirements and is not a simple process to manage. Installation can be complex and requires experienced operators. Costs of SCR are high, and have been rejected by States for this reason. EPA does not believe that SCR is a reasonable option for stationary SI lean burn engines. Consequently, this technology is not readily applicable to unattended oil and gas operation that do not have electricity.[1] However, the technology has been used successfully on lean-burn engines to meet Southern California's stringent limit of 0.15 g/hp-hr. The SCAQMD's staff report supporting Rule 1110 identifies SCR as a RACT on lean burn engines capably of achieving over 80% NOx control. The staff report also notes that SCR is a relatively high cost control technology option for RICE engines. Reasons given include the "capital cost for the catalyst, the added cost and complexity of using ammonia, and the instrumentation and controls needed to carefully monitor NOx emissions and meter the proper amount of ammonia." However they also note that the estimated costs have been declining over the past several years and are currently estimated to range from $50 to $125 per horsepower.

<u>Assumptions</u>

There is very little information in the literature regarding the incremental NOx emission reduction of SCR beyond lean burn technology for remote unattended oil and gas operations because there have been very limited installations of this technology for oil and gas compressor engines. Table 9 presents a summary of incremental SCR emission reductions and cost effective control estimates for SCR on a lean burn engine.[2]

Table 9: Incremental SCR Emission Reductions and Cost Effective Control Estimates for SCR

Incremental Cost-Effectiveness Estimates for ICE			**Control Techniques and Technologies**	
			Incremental	**Incremental NO_X**
Engine Type	**Control Comparison**	**Horsepower**	**NO_X Reduction**	**Cost-Effectiveness**
			(tons/year)	**($/ton of NO_X Removed)**
Lean Burn				
	From Low-Emission Combustion to SCR (96%)	300-500	**3.3**	8,800
		500-1000	**6.6**	10,300

There are several concerns regarding this information. First, it is not known if the emission reductions are based on actual performance tests or theoretical emission calculations. It is also not known what the reference basis is for the emission reduction of 6.6 tons per year of NOx. Review of CARB databases regarding NOx engine emissions does not provide any data regarding actual installations of SCR on lean burn engines for oil and gas operations. There is some very limited performance testing on SCR with lean burn engines that operate on pipeline natural gas (as opposed to field gas) for cogeneration facilities. Such emission data for cogeneration facilities is not applicable to oil and gas compressor engines. This is because cogeneration facilities tend to operate at a continuous load and have personnel present to operate the equipment. The CARB databases also provide testing of oil and gas SCR for high emitting 2 cycle engines (removal rates in the range of approximately 50 to 85 percent). These installations are not comparable to adding SCR to a well controlled engine.

Because of the limited application data for SCR on natural gas fired engines for oil and gas operations it is difficult to estimate the amount of potential emission reduction that could be achieved through the implementation of this technology. In addition, it is not clear how well this technology would perform in unattended remote applications. The limited data that does exist suggests that there may only be a small incremental reduction in NOx emissions beyond lean burn technology and this reduction would result at a very high incremental cost. This technology should be considered an emerging technology and merits additional testing for this unique application.

Because of non-linear chemistry involved in photochemical reactions of ozone and secondary aerosols that result in a reduction of visibility, NOx emission reductions estimated in this analysis may or may not result in equal improvement in ambient air quality levels. Also, excess ammonia slip within the discharge plume of an engine may accelerate the conversion of NOx emissions into particulate nitrate.

Table 10 presents CARB budgetary costs for the installation of SCR on lean burn engines.

Table 10: Cost-Effectiveness Estimates for ICE Control Techniques and Technologies

Selective Catalytic Reduction for Lean Burn				
Horse Power Range	**Capital Cost (S)**	**Installation Cost(S)**	**O&M Cost (S/year)**	**Annualized Cost (S/year)**
301-500	43,000	17,000	35,000	36,000
501-1000	116,000	33,000	78,000	78,000
1001-1500	132,000	53,000	117,000	148,000
Average gt 500 hp	**124,000**	**43,000**	**97,500**	**113,000**

It should be noted that in a white paper prepared by Thomas P. Mark regarding control of Engines in Colorado that he estimates the annual operating cost of SCR on an engine having a capacity of 1000 hp is approximately $140,000 per year and is consistent with the CARB estimate.[3]

Conclusions

The installation of SCR beyond lean burn technology is not a proven or cost effective technology at the present time. With additional development and testing for oil and gas operations, it may become an effective control technology for tertiary control of lean burn engines.

Endnotes

1 Federal Register Monday, June 12, 2006 40 CFR Parts 69, 63, et al. Standards of Performance for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Reciprocating internal Combustion Engines; Proposed Rule

2 California Environmental Protection Agency Air Resources Board, 2001, “Determination of Reasonably Available Control Technology.

3 Thomas P. Mark, October 31, 2003, Control of Compressor Engine Emissions Related Costs and Considerations.

Mitigation Option: NSPS Regulations

Description of Option

EPA is in the process of developing the first national requirements for the control of criteria pollutants from stationary engines. Separate rulemakings are in process for compression-ignition (CI) and spark-ignition (SI) engines. These NSPS will serve as the national requirements, leaving states with the authority to regulate more stringently as might be required in unique situations.

CI NSPS: The final NSPS for stationary CI (diesel) engines was published in the Federal Register on July 11, 2006. It requires that new CI engines built from April 1, 2006, through December 31, 2006, for stationary use meet EPA's nonroad Tier 1 emission requirements. From January 1, 2007, all new CI engines built for stationary use must be certified to the prevailing nonroad standards. (Minor exceptions are beyond the scope of this discussion.)

SI NSPS: The NSPS proposal for stationary SI engines, including those operating on gaseous fuels, was published in the Federal Register on June 12, 2006. Per court order, the rule is to be finalized by December 20, 2007. Like the CI NSPS, certain elements of the SI NSPS will be retroactively effective once finalized. The following summarizes the proposed requirements:

New Source performance Standards (NSPS)

EPA SI NSPS NPRM

NOx/CO/NMHC (g/bhp-hr)		2007		2008		2009		2010		2011	
		1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul
All engines	≤ 25 hp			40 CFR 90							
Gasoline & RB LPG	26-499 hp			40 CFR 1048							
	≥ 500 hp		40 CFR 1048								
Natural gas & LB LPG											
Non-emergency	26-499 hp			2.0/4.0/1.0						1.0/2.0/0.7	
	> 500 hp		2.0/4.0/1.0						1.0/2.0/0.7		
Emergency	> 25 hp					2.0/4.0/1.0					
Landfill / digester gas	< 500 hp			3.0/5.0/1.0						2.0/5.0/1.0	
	≥ 500 hp		3.0/5.0/1.0						2.0/5.0/1.0		

Notes: **NG & LB LPG, 25-50 hp, may instead comply with 40 CFR 1048.**
Engines ≤ 40 hp that are ≤ 1000 cc may instead comply with 40 CFR 90.
Emergency engines limited to 100 hours per year for maintenance and testing.

Since the proposed NSPS will become an EPA regulation, it will become the base case for emissions for new modified and reconstructed engines. As such, the benefits of this regulation are already incorporated into the Cumulative Effects emission inventories.

Mitigation Option: Optimization/Centralization

Description of Option

Under this option, natural gas fired internal combustion engines that are used to power various oil and gas related operations would be installed with appropriate sized engines (horsepower) for the activity being conducted. The advantage of this approach would be reducing the cumulative amount of horsepower deployed and might result in reducing emissions. This may also be accomplished by using larger central compression in lieu of deploying numerous smaller compressor engines at a number of individual locations such as well sites.

Assumptions

1) Current lease agreements for production cannot be easily changed.
2) Engine emission factors do not change with load.
3) Emission factors on small new, modified and reconstructed engines are consistent with large engines (proposed NSPS will require this).

Method

Short term emissions from compressor engines are based on the amount of fuel used which is a function of capacity (hp) and load. In determining annual emissions, the hours of operation are important. Assuming that emission factors do not change with load, as the load is reduced emissions will decrease. If it is assumed that all engines have the same rate of emissions, simply reducing the number of engines and operating them at higher capacity will likely result in the same amount of fuel usage and the same amount of emissions

Conclusions

Implementation of this option will not result in any quantifiable reduction in emissions.

Mitigation Option: Use of Oxidation Catalyst for Formaldehyde and VOC Control on Lean Burn Engines

Description of Option

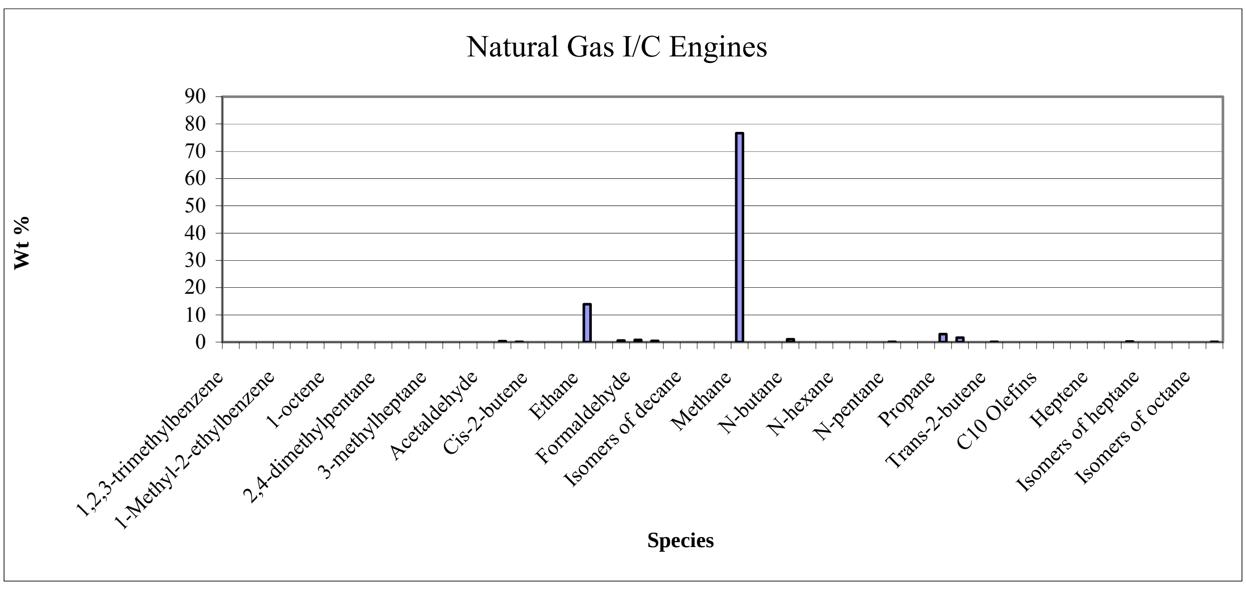
Using this option, existing or new lean burn natural gas fired internal combustion engines would be installed with oxidation catalyst to convert formaldehyde and VOC emissions to CO2. This technology requires the use of an air fuel ratio controller (AFR) in conjunction with the catalyst.

Assumptions

In developing emission inventories for the Four Corners Region, it was assumed that formaldehyde emissions from natural gas fired engines were 0.22 g/hp-hr for all types of engines. There is a large uncertainty in emission factors for formaldehyde which is why a conservative value of 0.22 g/hp-hr was assumed for all engines. In reality, lean burn engines have higher formaldehyde emissions than rich burn engines and therefore it is more appropriate to consider oxidation catalyst technology only for lean burn engines.

The emission inventory for VOC engines used manufacturers' emission factors. There is a large uncertainty if those emission factors represent total hydrocarbons (THC) or VOCs and also they do not include formaldehyde. THC includes methane (C1) and ethane (C2) which EPA does not regulate because they have low photochemical reactivity. The following figure presents the speciation of organics from natural gas fired engines from the EPA Speciate data base and indicates that the majority of the hydrocarbon emissions are methane and ethane. Thus, the projected reductions in hydrocarbon emissions may not affect ozone formation.

Composition of Hydrocarbon Emissions from Natural Gas Fired Engines

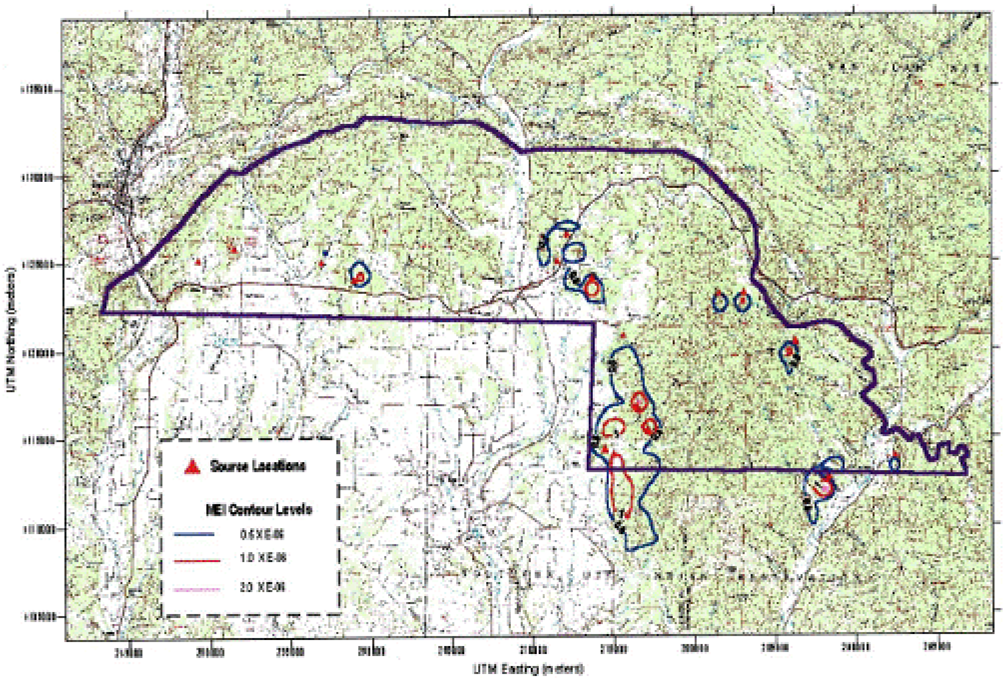


It was assumed that this technology could obtain a 90 percent reduction in hydrocarbons and 80 percent reduction in formaldehyde.

Previous modeling analyses of formaldehyde HAP impacts indicate that maximum impacts for the most likely exposed individual (MLE) are approximately 4x10-6 and have a very localized impact.[1,2] A plot indicating the formaldehyde impacts is presented in the following figure.[3]

Formaldehyde Isopleths from Northern San Juan EIS

Figure 7-5. HAP Incremental Risk Analysis for Formaldehyde MEI (Maximum Development)



Method

Table 11 presents the projected changes in formaldehyde and hydrocarbon emissions if oxidation catalyst were installed on new engines in Colorado and New Mexico.

Table 11: Estimated Changes in VOC and Formaldehyde Emissions with the Installation of Oxidation Catalyst

	VOC Reduction (t/yr)	Unmitigated VOC (t/yr)	Percent VOC Reduction	Formaldehyde Reduction (t/yr)	Unmitigated Formaldehyde (t/yr)	Percent Formaldehyde Reduction
Colorado	204	3115	7	42	471	9
New Mexico	1415	[Frame2] 42,117	3.4	382	365	40

In Colorado, the installation of oxidation catalyst on new engines greater than 300 hp[4] would result in formaldehyde emission reductions of 42 tons per year (a 9 percent reduction in emissions) in 2018. This option would also result in a reduction of 204 tons per year of VOC emissions (a 7 percent reduction in emissions) in 2018. In New Mexico, the installation of oxidation catalyst on new engines greater than 300 hp would result in formaldehyde emission reductions of 385 tons per year (a 40 percent reduction) in 2018. This option would result in a reduction of 1,415 tons per year of hydrocarbon emissions (primarily methane and ethane) and would correspond to a 3.4 percent reduction in total emissions in 2018.

Conclusions
Installing oxidation catalyst on new engines greater than 300 hp in Colorado would result in a reduction of approximately 42 tons per year of formaldehyde over current projected emissions in 2018. and 204 tons per year of VOCs (primarily methane and ethane).

Installing oxidation catalyst on new engines greater than 300 hp in New Mexico would result in a reduction of approximately 382 tons per year of formaldehyde and 1,415 tons per year of hydrocarbons (primarily methane and ethane) for new engines in 2018.

There is a large uncertainty in the VOC estimates because the emitted compounds may be methane and ethane which are not regulated VOCs.
Detailed modeling is necessary to determine the air quality benefit of such reductions with respect to VOCs.

Previous HAP modeling indicates that there are minimal and very localized HAP impacts from natural gas fired engines.

Endnotes
1 Dames and Moore 1999, "Southern Ute Environmental Impact Statement.
2 RTP Environmental, 2004, "Northern San Juan EIS 2002 Air Quality Impact Assessment Technical Support Document Northern San Juan Basin Coalbed Methane Environmental Impact Statement."
3 RTP Environmental, 2004, "Northern San Juan EIS 2002 Air Quality Impact Assessment Technical Support Document Northern San Juan Basin Coalbed Methane Environmental Impact Statement."
4 The lower size cutoff for current lean burn technology.

Mitigation Option: SNCR for Lean Burn Engines

<u>Description of the mitigation option</u>

SNCR stands for Selective Non-Catalytic Reduction. It is similar to Selective Catalytic Reduction (SCR), except that it lacks a catalyst. Like SCR, SNCR can be applied to lean-burn or diesel engines and urea or ammonia is injected into the exhaust manifold. Because it lacks a catalyst, SNCR has a lower conversion efficiency than SCR has.

Do not confuse SNCR with NSCR (Non-Selective Catalytic Reduction), which is applicable to rich-burn engines and uses a catalyst but does not use ammonia or urea as a reductant.

SNCR is used primarily for NOx reduction in boilers. It use in engines has been supplanted by SCR because it has a higher NOx reduction efficiency than SNCR.
SNCR at best can convert only about 60% of the NOx in the exhaust stream compared to about 90% for SCR. Like SCR, SNCR is subject to ammonia slippage.

Because of the low NOx removal rate, the uncertainty in application to natural gas fired engines and because more effective proven technologies exist, this option was not evaluated further.

Mitigation Option: Next Generation Stationary RICE Control Technologies

In evaluating the next generation RICE control technology, it is important to note that current engine technology has resulted in substantial NOx reductions in natural gas fired engines compared to engines that were installed 10 years ago. New large lean burn engines are achieving over 90 percent control reliably and cost effectively. In order for the next generation of controls to be implemented in the field they must achieve the same standards.

In the near term lean-burn technology could be applied to engines smaller than 500 hp. This is a decision to be made by the engine manufacturers with the driving force being emissions regulations. Alternatively, the engine manufacturers or after market control technology companies could partner with researchers at universities and/or national laboratories to test, verify and develop reliable rich burn engine non-selective catalytic reduction (NSCR) system retrofit kits (e.g., air/fuel ratio controllers, lambda sensors, TWC, ion sensors). A next generation NSCR system could include nitrogen injection to achieve higher levels of NOx control (> 95%). The NSCR for rich burn engines may be a very attractive option for the oil and gas industry and for control technology vendors since the technology is well developed and certified for automobile applications.

With that preface this analysis investigates the status of three new and/or evolving emissions-control technologies. They are: laser ignition, air-separation membranes, and lean-burn NOx catalyst (including NOx traps).

Laser ignition is under development in the laboratory, but it has not reached a point where technology transfer viability can be determined.

Air separation membranes have been demonstrated in the laboratory, but have not been commercially available because the membrane manufacturers do not have the production capacity for the heavy-duty trucking industry. Since stationary engines are a smaller market, there is a high probability that the membrane manufacturers could ramp up production in this area.

There are several variations of lean-burn NOx catalysts, but the one of most interest is the NOx trap. NOx traps are being used primarily in European on-road diesel engines, but are expected to become common in the U.S. as low-sulfur fuel becomes available. Applicability to lean-burn natural-gas engines is possible but it will require a fuel reformer to make use of the natural gas as a reductant.

I. Laser Ignition

Description of the Mitigation Option

Laser ignition replaces the conventional spark plugs with a laser beam that is focused to a point in the combustion chamber. There, the focused, coherent light ionizes the fuel-air mixture to initiate combustion. Applicability is primarily to lean burn engines, although laser ignition could be applied to rich burn engines. Air at high pressure is a good electrical insulator that requires high voltage to overcome. This limits the turbocharging pressure and compression ratio because the insulation on spark-plug wires breaks down at high voltage. Laser ignition is not subject to the same limitation, so a lean-burn engine with laser ignition can have a higher turbocharging pressure and a higher compression ratio than one with spark plugs.

Advantages of laser ignition compared to spark plugs include: 1. Longer intervals between shutdowns for maintenance because wear of the electrodes is eliminated, 2. More consistent ignition with less misfiring because higher energy is imparted to the ignition kernel, 3. The ability to operate at leaner air-fuel mixtures because higher energy is imparted to the ignition kernel, 4. The ability to operate at higher turbocharger pressure ratio or compression ratio because the laser is not subject to the insulating effect of high-pressure air, and, 5. Greater freedom of combustion chamber design because the laser can be focused at the geometric center of the combustion chamber, whereas the spark plug generally ignites the mixture near the boundary of the combustion chamber.

However, laser ignition has some unresolved research issues that must be resolved before it can become commercially available. These include: 1. Lasers are intolerant of vibration that is found in the engine's environment. 2. Some means of transmitting the laser light to each combustion chamber should be developed while accommodating relative motion between the engine and the laser. This might be done with mirrors or with fiber optics. Fiber optics generally lead to a simpler solution to the problem. 3. Current fiber optics is limited in the energy flux they can transmit. This leads to a less-than-optimum energy density at the focal point. 4. Wear of the fiber optic due to vibration may limit its lifetime. 5. The cost of a laser is such that multiple lasers per engine are too expensive. Therefore, a means of distributing the light beam with the correct timing to each cylinder must be developed.

Although laser ignition could be applied to rich burn engines, environmental benefits would accrue to lean burn engines. Laser ignition may be able to reduce NOx emissions by as much as 70% compared to spark-ignited engines.[1] However, in the reference cited, the baseline emissions for the engine with spark ignition were higher than the emissions that are currently achievable with lean burn engines. The more consistent ignition compared to spark ignition can be expected to decrease emissions of unburned hydrocarbons. The ability to operate at leaner air-fuel ratios and at higher turbocharging pressure are responsible for the decrease of NOx emissions because of lower combustion temperatures. Laser ignition systems have not been developed to the point where the effect of improved combustion chamber design can be measured. It is reasonable to expect that a better combustion chamber design would further decrease emissions of unburned hydrocarbons, carbon monoxide, and NOx. In actual operation of the engine, misfiring of one or more cylinders contributes to loss in efficiency and increase in emissions. With the laser ignition system, misfiring can be significantly reduced. Whether laser ignition combined with lean-burn engine technology can meet the Southern California NOx limit of 0.15 g/hp-hr will be the subject of further research.

One of the advantages of laser ignition is its potential to eliminate downtime due to the need to change spark plugs. This advantage would accrue to both rich burn engines and lean burn engines. Higher efficiency due to near elimination of cylinder misfirings is an additional benefit.

Laser ignition would compete with selective catalytic reduction (SCR) applied to lean-burn engines. Although costs are unknown at this time, laser ignition is likely to be the lower cost alternative.

A tradeoff for engine manufacturers, assuming that laser ignition can be developed to the point of commercial feasibility, is whether or not to develop retrofit kits. Retrofits would be expected to take away sales of new engines.

A tradeoff for engine users is whether to continue using spark ignition or to purchase a laser ignition that is initially more expensive but has a future economic benefit.

Another tradeoff for engine users is whether to retrofit laser ignition to an existing engine or to spend more money for a new engine in return for future benefits.

<u>Assumptions</u>

In the analysis, it is assumed that the limitations of laser ignition described above can be overcome through research and development. It is further assumed that NOx emissions can be reduced by 70% compared to spark-ignition lean-burn engines. Until more research is done, the 70% reduction is most likely an upper limit. This reduction is due to the ability to operate at higher turbocharging pressure, hence leaner air/fuel ratios and lower combustion temperature than is currently possible with spark-ignition engines. Since lean-burn engines are primarily those over 500 hp, the technology is assumed to apply only to engines larger than 500 hp. The technology is assumed to be retrofitable to any engine that uses 18-mm spark plugs, so it is applied to all engines, new and existing, in the Colorado and New Mexico databases.

Conclusions

Testing in the laboratory has shown potential emissions reductions in the 30% to 60% range, which may or may not be achievable when this technology is implemented in the field.

II. Air-Separation Membranes

Description of the Mitigation Option

The purpose of air-separation membranes is to change the proportion of nitrogen to oxygen in air. A membrane can be optimized to either enrich the oxygen content or to enrich the nitrogen content. Both the oxygen enrichment mode and the nitrogen enrichment mode have been tested in the laboratory with diesel engines. The nitrogen enrichment mode has been tested in the laboratory with Natural Gas Fuel as well. The oxygen enrichment mode and the nitrogen enrichment mode are mutually exclusive.

Oxygen enrichment produces a dramatic reduction in particulate emissions in diesel engines at the expense of increased NOx emissions. However, Poola[2] has shown that the effects are non linear such that a small enrichment (1 percentage point or less) produces a significant reduction in particulate emissions with only a small increase in NOx emissions. By retarding the injection timing, one can achieve a reduction in both NOx and particulate emissions. The overall benefits of oxygen enrichment are relatively small and have not been tested with natural gas-fueled engines, so it will not be considered further.

Nitrogen enrichment produces the same effect on emissions as exhaust-gas recirculation; NOx decreases. It can be applies to either diesel or rich-burn natural-gas engines. Unlike exhaust-gas recirculation (EGR), nitrogen-enriched air contains only the components of pure air. Manufacturers of both diesel and natural-gas engines are concerned that components of exhaust gas could shorten the life of the engines with EGR. In the case of diesel engines, it is clear that exhaust particulate matter could cause wear between the piston rings and cylinder liners. Even in the case of rich-burn engines, the exhaust gas contains condensed liquids that may cause wear. As recently as August, 2004, the Engine Manufacturers Association does not consider EGA to be a viable option for rich-burn engines.[3] Thus, nitrogen enriched air is seen as an alternative to EGR because it contains no components that are not found in air. Published data from tests in natural-gas engines show engine-out NOx reductions of 70% are possible with nitrogen-enriched combustion air.[4] When combined with non-selective catalytic reduction (NSCR), the overall NOx reduction can reliably exceed 90%.

The cost of nitrogen-enriched air systems are expected to be higher than that of EGR. However, nitrogen-enriched air does not have components that can cause increased engine wear as EGR does.

Assumptions

Only nitrogen-enriched air is considered in this analysis. The technology is assumed to be retrofittable to all rich-burn engines, new and existing. While nitrogen-enriched air can be combined with non-selective catalytic reduction (NSCR), only the effects of nitrogen-enriched air are considered here. The effect is assumed to be the same as that of EGR; it can produce a 70% reduction in NOx emissions. This is most likely an upper limit.

Conclusions

Testing in the laboratory has shown potential emissions reductions in the 50% to 90% range, which may or may not be achievable when this technology is implemented in the field. The upper end assumes integration as a component of a reasonably well-designed (use of current state of the art air fuel ratio controllers / sensor technologies) NSCR system.

III. Lean-Burn NOx Catalyst, Including NOx Trap

Description of the Mitigation Option

Lean-burn NOx catalysts have been under development for at least two decades in the laboratory with the intent of producing a lower cost alternative to SCR. They do not have the ammonia slip problem associated with SCR, but they typically use some of the fuel as a reductant.

Several variants of lean-burn NOx catalysts have been studied: (1) Passive lean-burn NOx catalysts simply pass the exhaust over a catalyst. The difficulty has been low NOx conversion efficiency because the oxygen content of a lean-burn exhaust works against chemical reduction of NOx. Conversion efficiencies of the order of 10% are typical.[5]

(2) Active lean-burn NOx catalysts use a fuel as a reductant. The catalyst decomposes the fuel, and the resulting fuel fragments either react with the NOx or oxidize. Methane is much more difficult to decompose than heavier fuels, such as diesel [aardahl.pdf. A wide range of NOx reduction efficiencies from 40% to more than 80% have been published. [6,7] Variants of active lean-burn catalyst systems may use plasma or a fuel reformer to produce a more effective reductant than neat fuel.[8,9,10]

(3) NOx trap catalysts are a more recent development that has seen some laboratory success. Operation is a two-step cyclic process. In the first stage the NOx trap adsorbs NOx while the engine operates in a lean-burn mode. In the second stage, the engine operates with excess fuel in the exhaust. The fuel decomposes on the catalyst and reduces the NOx to molecular nitrogen and water. With natural gas as the fuel, a fuel reformer is necessary to break up the extremely stable methane molecule for use as a reductant When the supply of trapped NOx is exhausted, the system reverts back to first-stage operation. NOx reduction efficiencies in excess of 90% have been published.[11] A sophisticated engine control is required to make this system work.

NOx traps have been proven to be effective and have seen some limited commercial success in Europe. NOx traps are one of the reasons for the dramatic reduction in sulfur content of diesel fuel in the U.S. Fuel-borne sulfur causes permanent poisoning of NOx-trap catalysts. There are doubts regarding the NOx conversion efficiency levels after 1,000 hours or longer use. This should be evaluated, as well as the durability of the equipment.

Active lean-NOx catalysts have seen limited commercial success because they are less effective than NOx traps and are not being considered for on-road diesel engines. Some instances of formation of nitrous oxide (N2O) rather than complete reduction of NOx have been reported.

Passive Lean-NOx catalysts do not provide enough NOx reduction to be considered viable.

Costs of retrofitting a lean-burn NOx catalyst are estimated at $6,500 to $10,000 per engine [retropotentialtech.htm.][11] $15,000-$20,000 including a diesel particulate filter [V2-S4_Final_11-18-05.pdf] for off-road trucks.[12] Estimates are $10-$20/BHP for stationary engines [icengine.pdf]. [14]

Little information on the cost of NOx-trap catalytic systems was found. The overall complexity of a NOx-trap system is only slightly more than that of a lean-burn NOx catalyst, so costs can be expected to be slightly higher. With methane-burning engines, both active lean-burn NOx catalysts and NOx-trap catalysts require a fuel reformer or other means of dissociating methane. This will add an increment of cost.

Both active lean-NOx technology and NOx-trap technology impose a fuel penalty of 3-7%.

Assumptions

Only NOx-trap catalysts, which can remove up to 90% of the NOx in the exhaust stream are considered for this analysis. The technology is applicable to lean-burn engines, which are considered to be those having more than 500 hp in the Colorado and New Mexico databases. The technology is assumed to be retrofitable, so it is applied to all new and existing engines greater than 500 hp.

Conclusions

Testing in the laboratory has shown potential emissions reductions in the 40% to 70% range, which may or may not be achievable when this technology is implemented in the field.

Summary

Three technologies are reported: laser ignition, air-separation membranes, and lean-burn NOx catalyst.

Laser ignition is not presently a commercial product. The impetus for investigating it is the potential to eliminate the need for changing spark plugs. It will also allow operation at leaner air-fuel ratios, higher compression ratios, and higher turbocharging pressure. Leaner air-fuel ratios imply lower engine-out NOx emissions so the after treatment can be smaller or can give lower overall emissions. Higher compression ratios and turbocharging ratios imply higher engine efficiency.

Air-separation membranes used to deplete oxygen from the combustion air can serve as a clean replacement for EGR. That is, an engine using oxygen-depleted air would not be ingesting combustion products. Engine manufacturers are concerned that EGR will shorten the life of their engines and lead to premature overhauls and warranty repairs. The technology has been demonstrated in the laboratory, but has not been used for heavy-duty trucks because membrane manufacturers do not have enough production capacity for the market. Stationary engines are a smaller market, so the membrane manufacturers may be able to ramp up their capacity with stationary engines. Applicability is to diesel engines and rich-burn natural-gas engines. Oxygen-depletion membranes are not applicable to lean-burn natural-gas engines.

Lean-burn NOx catalysts have several forms, but the one that is of most interest is the NOx-trap catalyst. Unlike SCR, lean-burn NOx catalysts use the engine's fuel as a reductant and do not require a separate supply of reductant. It is a well proven in the laboratory and is commercially available in Europe for diesel engines, but it requires a fuel reformer if natural gas is used as the reductant. A sophisticated control system is required to cycle the engine between its two modes of operation. Ammonia slippage is not an issue with NOx traps, and if there is any slippage of unburned fuel it can be removed with an oxidation catalyst. Cost is high but less than that of SCR systems. A large part of the cost of SCR is the ammonia or urea reductant necessary to make it work. A disadvantage of NOx traps is that they are intolerant of fuel-borne sulfur. For diesel fuel, the sulfur content must be less than 15 ppm. Fuel-borne sulfur permanently poisons the catalyst. Since fuel is used as a reductant, there is a fuel consumption penalty of 3-7%.

Endnotes

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2 R.B. Poola and R. Sekar, “Reduction of NOx and Particulate Emissions by Using Oxygen-Enriched Combustion Air in a Locomotive Diesel Engine,” Transactions of the ASMR, Vol. 125, p524ff, April., 2003.

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[6] Park, op cit.

[7] 'Emission Control Technology for Stationary Internal Combustion Engines, Status Report," Manufacturers of Emission Controls Association, 1660 L St. NW, Washington, DC, July 1997.

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[10] Magdi K. Khair, partha P. Paul, and Michal G. Grothaus, "Synergistic Approach to Reduce Nitrogen Oxides and Particulate Emissions from Diesel Engines, 08-9051," Southwest Research Institue, 1999.

[11] James E. Parks II, H. Douglas Ferguson III, and John M.E. Storey, "NOx reduction with Natrual Gas for Lean Large-Bore Engine Applications Using Lean NOx Trap Aftertreatment," Oak Ridge National Laboratory, Knoxville, TN, 2005.

[12] "Summary of Potential Retrofit Technologies, Technical Summary," U.S. Environmental Protection Agency, March, 2006.

[13] "WRAP Off-raod Diesel Retrofit Guidance Document, Volume 2, Section 4," November, 2005.

[14] Manufacturers of Emissions Controls Association, op cit.

Mitigation Option: Automation of Wells to Reduce Truck Traffic

Assumptions

About 50% of traffic on dirt roads in the Four Corners region is oil and gas related.

Substantially less than widespread implementation is likely, assume 25%.

Emissions estimates for road dust are of medium to low quality.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have an EPA-recommended factor applied that estimates the transportable fraction, i.e. that which would move beyond the immediate vicinity.

Automation would not quite “zero out” vehicle-related emissions for those wells that are automated because of non-routine maintenance, perhaps it would be reduced by 80%.

Vehicle miles traveled is proportional to dust generated.

Method

Applying the percent reduction, 80% reduced by 50% to account for extent of oil and gas traffic and further reduced by 75% to account for effectiveness. So, the over all reduction would be 10%.

Conclusions

For road dust, the total PM10 emissions in the region are 1959 tpy (tons per year), while the total of PM2.5 is 196 tpy based on WRAP inventory information. Hence, the estimated reduction in road dust emissions because of automation would by 196 tpy of PM10 and 20 of PM2.5.

For tailpipe emissions, the total NOx emissions in the region are 916 tpy, which means the reduction because of automation would be 92 tpy.

Mitigation Option: Reduced Truck Traffic by Centralizing Produced Water Storage Facilities

Assumptions

About 50% of traffic on dirt roads in the Four Corners region is oil and gas related.

Substantially less than widespread implementation is likely because it is voluntary, assume 20% participation which is a bit higher than is usually assumed for regulatory programs.

Emissions estimates for road dust are of medium to low quality.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have an EPA-recommended factor applied that estimates the transportable fraction, i.e. that which would move beyond the immediate vicinity.

Hauling of produced water constitutes about 20% of total O&G traffic.

Streamlining hauling might reduce such traffic by about 50%.

The relative mix of heavy duty compared to light duty vehicles is unknown, so estimating emissions reductions for this option might be a bit conservative since it is based on an overall average that includes both light- and heavy-duty and the approach is intended just for heavy-duty which produce more dust on a per unit basis.

Method

Based on the above assumptions of 50% of total traffic is oil and gas related, of which 20% are hauling produced water and of which 20% will likely undertake the program. Therefore, of the total unpaved road traffic generating road dust, 2% would be reducing emissions under this approach. One would then apply the 50% control efficiency.

Conclusions

For road dust, the total PM10 emissions in the region are 1959 tpy (tons per year), while the total of PM2.5 is 196 tpy based on WRAP inventory information. Hence, the estimated reduction in road dust emissions because of automation would by 39 tpy of PM10 and 4 tpy of PM2.5.

Mitigation Option: Reduced Truck Traffic by Efficiently Routing Produced Water Disposal Trucks

Assumptions

About 50% of traffic on dirt roads in the Four Corners region is oil and gas related.

Emissions estimates for road dust are of medium to low quality.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have an EPA-recommended factor applied that estimates the transportable fraction, i.e. that which would move beyond the immediate vicinity.

Hauling of produced water constitutes about 20% of total O&G traffic.

Streamlining hauling might reduce such traffic by about 50%.

Miles traveled is proportional to dust generated.

The relative mix of heavy duty compared to light duty vehicles is unknown, so estimating emissions reductions for this option might be a bit conservative since it is based on an overall average that includes both light- and heavy-duty and the approach is intended just for heavy-duty which produce more dust on a per unit basis.

Method

Based on the above assumptions of 50% of total traffic is oil and gas related, of which 20% are hauling produced water. Therefore, of the total unpaved road traffic generating road dust, 2% would be reducing emissions under this approach. One would then apply the 50% control efficiency.

Conclusions

For road dust, the total PM10 emissions in the region are 1959 tpy (tons per year), while the total of PM2.5 is 196 tpy based on WRAP inventory information. Hence, the estimated reduction in road dust emissions because of automation would by 196 tpy of PM10 and 20 tpy of PM2.5.

Mitigation Option: Reduced Vehicular Dust Production by Covering Lease Roads with Rock or Gravel

Assumptions

About 25% of traffic on dirt roads in the Four Corners region is on oil field lease roads.

Once applied, the improved surface would be maintained regularly by grading and reapplying gravel or rock.

Emissions estimates for road dust are of medium to low quality.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have had an EPA-recommended factor that estimates the transportable fraction, i.e. that which would move beyond the immediate vicinity.

The level of emissions reductions achieved by the application of gravel to roadways can vary from place to place.

Considering uncertainties in road dust emissions estimates, the more conservative end of a range will be used.

Method

The total annual road dust emissions of PM10 in the Four Corners region are 1959 tpy (tons per year), and 196 tpy of PM2.5 based on the inventory information from the WRAP.

Based on a comprehensive EPA study (Raile, 1996) conducted in the Kansas City, Missouri area, emissions of PM10 were reduced by 42% to 52% by the application of gravel.

Conclusions

Therefore, emissions of PM10 on lease roads would be reduced by about 206 tpy, and by about 21 tpy of PM2.5. This is based on the following:

reduction of particulate from lease roads =
total road dust emissions times 25% times 42%.

References

Raile, M.M. 1996. Characterization of Mud/Dirt Carryout onto Paved Roads from Construction and Demolition Activities. U.S. EPA. EPA/600/SR-95/171.

Mitigation Option: Reduced Vehicular Dust Production by Enforcing Speed Limits

Assumptions

The average posted speed is 30 mph.

About half of the vehicles on dirt road exceed the posted limit by more than 5 mph. The average for these drivers is 40 mph or 10 mph over.

Therefore, the reduction in speed for those exceeding posted limits would be about 10 mph if enforcement was undertaken and was 100% effective. Such enforcement is not 100% effective.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have an EPA-recommended factor that estimates the transportable fraction, i.e. how much would move beyond the immediate vicinity.

The effectiveness of enforcement initiatives is dependent on resources allocated.

Method

The equation for estimating road dust PM10 emissions from EPA's AP-42 is:

((1.8*(silt content/12)^.1) * (veh. Speed/30)^.5) - .00036) /
(surface moisture/.5)^.2

Therefore, adjusting the vehicle speed would change the multiplier in the numerator from 1.15 (i.e. (40/30)^.5) to 1.0 (i.e. (30/30)^.5).

So, assuming even 50% effectiveness in mitigating speeding, and generally the assumption is lower, the reduction from enforcing a 30 mph speed limit on dirt roads in the entire Four Corners region would be about 7.5%.

Conclusions

Remembering that half of the traffic on dirt roads are exceeding the speed limit by more than the threshold 5%, applied to the total road dust emissions of PM10 of 1959 tpy, the reduction would be approximately 73 tpy. The reduction in PM2.5 from a total of 196 tpy would be 7 tpy.

Mitigation Option: Emissions Monitoring for Proposed Desert Rock Energy Facility to be Used Over Time to Assess and Mitigate Deterioration to Air Quality in Four Corners Region

Assumptions

Generally, much post-construction ambient monitoring for permitted facilities by the source is conducted on-site. Air quality permits generally contain conditions to require continuous emissions monitoring from the stacks for criteria pollutants. New federal mercury rules will require continuous emissions monitoring for mercury for Desert Rock Energy Facility beginning in 2010.

Given the tall stack heights of the proposed facility, the greatest air pollution impacts from emissions from the facility will be quite some distance from the facility.

Review of Proposed Approach

Continuous PM2.5 monitoring of primary fine particulate by the facility on-site would not likely provide useful information where the effect of emissions would be well downwind, plus direct fine particulate emissions by more modern power plants are usually not substantial. However, monitoring fine particulates and its chemical components (including ammonia) at off-site locations where models indicate significant impacts from the facility would be useful. Also, since much fine particulate is formed in the atmosphere rather than emitted directly, measurements of sulfur dioxide and oxides of nitrogen offsite would also be useful.

Stack mercury measurements might be useful from a research perspective in performing source apportionment work in the Four Corners region.

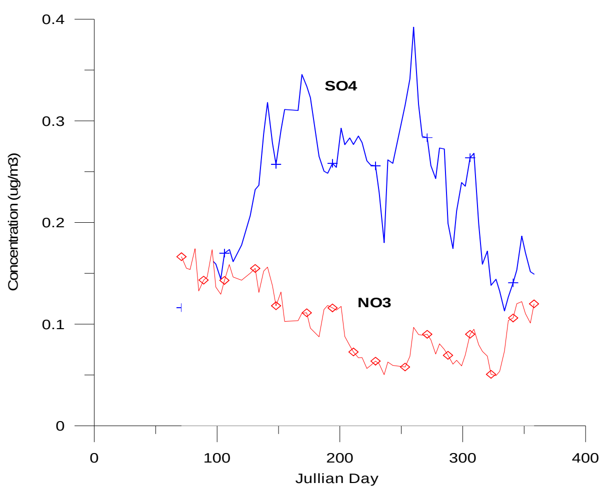
As is discussed above, on-site ambient monitoring of volatile organic compounds (VOC) may not be an effective means of understanding the ambient impact of these emissions, but off-site monitoring of ozone precursors like VOC and nitrogen oxides at predicted maximum impact locations would be useful.

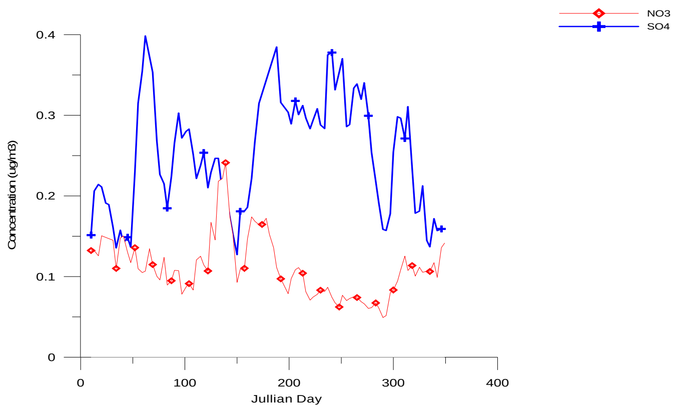
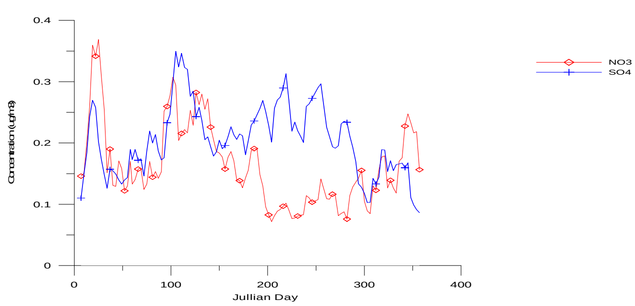
CUMULATIVE EFFECTS: PUBLIC COMMENTS

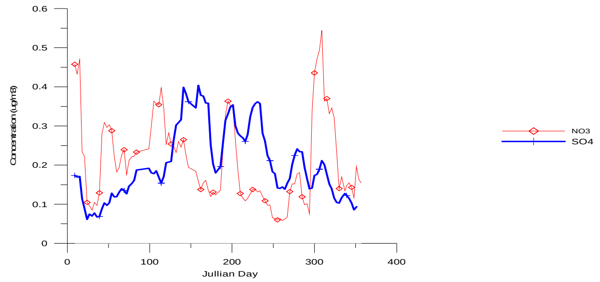
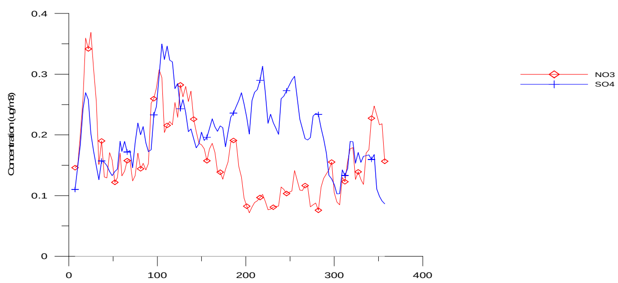
Cumulative Effects Public Comments

Comment	Mitigation Option
I have been concerned for many years about the air quality of the Four Corner's region because of the coal fired power plants in N.M. I attended two of the Four Corner's air quality forums in the past and was disturbed by their reports. As a nurse, I am especially concerned for the health of the Native Americans and other people who reside close to the power plants because of their incidence of lung disease. As a resident of La Plata canyon for 20+ years with a high mercury level, I am concerned about my own health and notice more air pollution, lack of visibility, every time I hike in the mountains. I believe for everyone's health, alternative sources of energy; e.g. solar, wind energy is a much better solution and would still serve as a revenue source to the Navajo nation. Desert Rock should not be built and the others should be phased out as planned many years ago or at least upgraded to standards that were set by the Clinton administration.	General Comment
We do NOT need another power plant in the 4 Corners. I notice the dirty air in this area all of the time and especially on weekends. Drive up from Albuquerque and see the air get dirtier. Also, go out from the 4 Corners and notice the beautiful blue skies as you progressively leave the area. I teach school and stress to my students they need to take care of the this planet earth because there is no spare earth. I would like to stress to everyone else that this needs to be done. Solar, wind and other energy sources should be used.	General Comment
It breaks my heart to think that another coal fired plant may be added to our "pristine" 4 corners area. Even in Pagosa Springs we have some hazy smog some days, and when driving south and west of Farmington, that horrible yellow-brown cloud can be seen for miles! I was shocked to see that poisonous cloud in Monument valley, and northwest Utah. It's all pervasive now so I can't imagine what it will be like with more coal -spewing plants. We must use non polluting energy sources for the health of all of us!	General Comment
The Task Force report presents data on the potential emission reductions for the Four Corners Power Plant and the San Juan Power Plant. The Cumulative Effects Work Group needs to evaluate potential power plant mitigation options that are presented in the report and develop a quantitative summary of all potential mitigations options which have technical merit. It is useful to place the emission reductions suggested for power plants in perspective to those developed for oil and gas sources. As stated in the Draft Report, for the Four Corners Power Plant the installation of presumptive BART could result in SO_2 emission reductions from a minimum of 12,455 tons per year to a maximum of 19,927 tons per year. Similarly, NO_x emission reductions could range from 13,651 tons per year to 57,118 tons per year. Since SO_2 and NO_x emissions are considered as having similar visibility impairment potential, the magnitude of the total emission reductions possibly affecting visibility could range from 26,106 to 77,045 tons per year. For the San Juan Power Plant using data presented in the Task Force Report, estimated SO_2 emission reductions could be approximately 9,000 tons per year and NO_x reductions could be approximately 11,000 tons per year. For this plant the combination of SO_2 and NO_x possible reductions of 20,000 tons per year might be achieved. The information contained in the Draft Report regarding possible emission reductions for this source is not as complete as for the Four	General Comment

Comment	Mitigation Option
Corners Plant and additional data should be developed and presented. If the suggested emission reduction strategies were implemented at both plants, total SO2 and NOx emission reductions of visibility impairment pollutants could range from 46,106 tons per year to 97,046 tons per year. In addition, review of the emission data in the Draft Report indicates that at the Four Corners Power Plant NOx emissions are greater than SO2 emissions (Figure 2 FCPP Emission Trends). However, in 2003 SO2 emissions were further reduced so that the ratio of NOx to SO2 emissions increased. At the San Juan Power Plant prior to 1990, SO2 emissions were greater than NOx emissions while in 1999 SO2 and NOx emissions were equal (Figure 1 San Juan SO2 and NOx). After that time, SO2 emissions were less than NOx emissions. The trends in emissions at these facilities may be important in understanding the trends in the IMPROVE monitoring data. Engineering and economic feasibility studies need to evaluate the ability of the facilities to continuously achieve emission reductions in a cost effective manner. The potential emission reduction that could be realized with the installation of additional controls on power plants need to compared with the emission reductions reported by the Draft Task Force Report for oil and gas sources. The installation of NSCR on existing small engines in Colorado and New Mexico could result in emission reductions of approximately 10,244 tons per year. These emission reductions are only a small fraction of the reductions possible from power plants (minimum ratio of power plant reduction to oil and gas reductions 4.5 – maximum ratio of power plant reduction to oil and gas reductions 9.5).	
The Draft Task Force Report presents recommendations for mitigating emissions from drilling rig diesel engines. At the present time there is insufficient information regarding the level of emissions from these sources in the region. The Cumulative Effects Group should develop emission data regarding the magnitude of emissions in both Colorado and New Mexico and then develop estimates of potential emission reductions that could be achieved. The emission calculations should be based on site specific information that represents the length of time to drill a new well, engine loads and engine capacity. One important fact that needs to be considered is that the drilling rig engines are typically replaced at a frequency of every 5 years (replaced not rebuilt). This rate of turnover is very important because the engines are replaced with the required current control technology. This should be the baseline against which alternative mitigation options should be considered. It is recommended that the Cumulative Effects Group continue to analyze and evaluate emission reduction options for this source group.	General Comment
The following plots present selected years of rolling 5 data point averages of the SO4 and NO3 concentrations compared to Julian day for the IMPROVE data from Mesa Verde. Using a rolling 5 data point average provides some smoothing of the data but allows correlations between SO4 and NO3 to be observed. The plots for 1988 and 1990 indicate a large fraction of coincident peaks of SO4 and NO3. This is an important finding because it suggests that these events may result from coal fired sources because natural gas fired sources or mobile sources do not emit significant SO2. In addition, NO3 concentrations are smaller than SO4 concentrations. The data from 2002, 2003 and 2004 indicate that a change has occurred in the relationship of SO4 and NO3 measurements and that there is a very strong correlation of SO4 and NO3	General Comment

Comment	Mitigation Option
events, again suggesting a coal fired source. However, in 2002, 2003 and 2004 NO3 concentrations are equal to or greater than SO4 concentrations. As mentioned in the power plant emission section, SO2 reductions began in 1999 and after that time NOx emissions were greater than SO2 emissions. This trend in changes in emissions is very consistent with the monitoring data and again suggests visibility impacts are likely from coal fired sources. This is a preliminary hypothesis that needs more evaluation and may explain why NO3 levels have been increasing at Mesa Verde. If this finding is confirmed, it has important ramifications regarding improvement in air quality. This is the type of focused analyses that needs to be conducted before mitigation options are selected and implemented.  **1988 SO4 and NO3 Concentrations 5 Day Running Average** **Mesa Verde**	

Comment	Mitigation Option
 1990 SO4 and NO3 concentrations 5 day running average  **2002 SO4 and NO3 Concentrations 5 Day Running Average Mesa Verde**	

Comment	Mitigation Option
 **2003 SO4 and NO3 Concentrations 5 Day Running Average** **Mesa Verde**  **2004 SO4 and NO3 Concentrations 5 Day Running Average** **Mesa Verde**	
last paragraph before Suggestions for Future Work...should the reference be to Table 2 rather than Table 1?	Overview of Work Performed

Comment	Mitigation Option
Table 1 - Selective Catalytic Reduction (SCR) on Drilling Rig Engines: It is stated "that some data exists on drilling emissions. The State of Wyoming evaluated this technology based on a pilot study in the Jonah Field & concluded that is not a cost effective technology, but further analysis is needed." This paragraph references the cost analysis WY did for SCR on diesel rig engines, but does not provide or reference any information on what conditions and assumptions WY used in conducting this analysis. If possible the CE workgroup should obtain and review the WY analysis on SCR, in addition to other diesel control options WY analyzed. Table 1 - Follow EPA New Source Performance Standards (NSPS) for RICE: EPA suggests revising the Summary of Result first sentence "This proposed emission standard will become the baseline for new, **modified, and reconstructed** engines. Table 1 - Install Non Selective Catalytic Reduction (NSCR) on Rich Burn Engines for RICE. It is unclear in the Summary of Result what EPA performance standard is being referenced, and how the 4 Corners Task Force Interim Emissions Recommendations for Stationary RICE have been considered by the CE workgroup. The NSPS for spark ignition engines will apply to **new, modified, and reconstructed** units starting in January 2008. The 4 Corners Task Force Interim Emissions Recommendations for Stationary RICE notes that BLM/USFS, at the request of CO and NM, is currently requiring NSPS comparable emission limits on as a Condition of Approval for their Applications for Permits to Drill. The States' request was that BLM/USFS immediately establish in every Application for Permit to Drill (APD) a nitrogen oxide (NOx) limit of 2.0 grams per horsepower hour for all **new and replacement** engines less than 300 hp (excluding engines with horsepower less than 40). In addition, New Mexico and Colorado have requested that for all new and replacement engines greater than 300 hp, the BLM and the USFS establish in every APD a NOx limit of 1.0 gram per horsepower hour. EPA Region 8 formally supports both these requests from Colorado and New Mexico. It should also be noted that the Mitigation Option: Interim Emissions Recommendations for Stationary RICE section in the Draft Mitigation Options Report states that "BLM in New Mexico and Colorado are currently requiring these emission limits as a Condition of Approval for their Applications for Permits to Drill. These limits currently apply only to **new and relocated** engines ... (compressors assigned to the well APD)..." In developing assumptions for potential NOx reductions from this requirement in APDs, how did the CE workgroup determine, or assume, what percentage of the existing engines (compressors) in the 4 Corners area would be required to meet this requirement?	Overview of Work Performed

Comment	Mitigation Option
1. Given electric compression would shift emissions generated from NG compressor engines through use of electric engines to emissions from power generation (i.e., "the grid"), this option is clearly "cross-cutting." We recommend that the coordination with the Power Plant WG in the analysis of this option. 2. We were unable to reproduce the emission reduction numbers from the data provided in the analysis (tons/yr deltas provided in Table 4). Based on the data provided we calculate a total of 631 tons/yr reductions in NOx and SO2 based the 25 worst engines and the average power plant emissions in Table 3. 3. In course of installing electric compression to replace the natural gas fired compression engines, the analysis correctly assumes that the emission of pollutants will shift from the replaced compressor engines to increased electric load demand from the grid. In course of review of the Natural Resources Defense Council (NRDC) "Emission Data for the 100 Largest Power Producers", it appears that baseline average emission factors used for emission difference calculation are the national average emission factors for the identified owner utility companies (average of all plants, regardless of location or on which power grid). The electric power for electric compression will come from the Western Grid which draws power from generating stations in the western United States. Among the three electric power producers, Xcel is the largest producer with 81,283,493 MWhs capacity compare to 21,230,675 MWhs for both PNM and Tri-state. The baseline average emission factors based on national average emission factors of these three electric power producers have potential to distort the emission difference calculation because Xcel's power generation facilities in Minnesota, South Dakota, Texas, and Wisconsin are not supplying electricity to the Western Grid. A brief description of grid system is provided later in this document. A better measure of the effectiveness of this option would be the use of average NOx and SO2 emissions from Four Corners Generating Station and San Juan Generating Station. In case example case provided in the analysis, replacing 25 worst engines with total 2,701 hp in NM side with electric compression, will result in net NOx + SO2 reduction of 610 tons/year. A net NOx +SO2 reduction of approximately 20,000 tons/year can be achieved by replacing all rich burn engines (approximately 1,500 in NM inventory) emitting greater than 5 g/hp-hr. Although it may not be practical or economically feasible to replace all rich burn compressor engines with electric motors, further analysis of the locations/ configurations of existing compressor stations may reveal that conversion to electric is practical and makes sense. Factors like proximity to the electric grid, ROW, number of engines, are factors that would need to be evaluated. 4. The electricity for the electric compression in the San Juan area will be drawn from Western Interconnect or Grid. We recommend that a good approximation for baseline emission factors will be the averages of emission factors for the power plants supplying electricity to the Western Grid. The following steps can be taken to obtain the baseline average emission factors for the emission difference calculation: a. The average emission factors for fossil fuel powered power plants supplying electric power to the Western Grid can be calculated using the emission data	Install Electric Compression

Comment	Mitigation Option
from the EPA's CAMD inventory. The EPA's Clean Air Market Data (CAMD) (http://camddataandmaps.epa.gov/gdm/index.cfm) provides NOx, SO2, and CO2 emission as well as heat input for the Title IV power generating units. b. The net power generation by state by type of producer by energy source is available at the Energy Information Administration (EIA) website (http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html). c. A fraction between calculated average baseline emission factors for the Western Grid based on EPA data and the total power generation for the Western Grid obtained from EIA's website will used to obtain the average baseline emission factors for emission difference calculations. 5. The worst case NOx emissions from coal-fired plants is 4.5 lbs/MWh, which is equivalent to 1.5 g/hp-hr. The coal-fired plants produce a lot more NOx emissions than the gas field sources do: 160,264 tons/year compared to 38,632 tons/year. A 5% reduction of NOx emissions from the coal-fired plants is the same as a 21% reduction in NOx from gas field sources. 6. We recommend that the Task Force evaluate on-site lean-burn electric generators as an alternative power source for electric compression.	
The SUGF recommends further research and testing of this mitigation option to help determine the amount of emissions reduction that can be accomplished on a continual, reliable basis. If technology could be developed and maintained on a regular basis, this option could prove to be valuable in retrofitting existing rich burn units.	Use of NSCR for NOx Control on Rich Burn Engines
In the section Mitigation Option: Use of NSCR for NOx Control on Rich Burn Engines it is stated in the Assumptions (p. 13): "Currently, recent EIS RODs in Colorado and New Mexico require performance standards for new engines that will accelerate the implementation of the 2008 and 2010 federal NSPS for non road engines." The term "replacement" is not used, only "new" engines. What is the CE workgroups understanding related to what type of engines would fall under the replacement category, and was this type of engine considered in the assumptions as being retrofitted to meet the interim recommendation of 2 g/hp/hr? Engine Size < 100 hp Case 1 (p. 14): It is stated that "it was assumed that NSCR for this situation would reduce NOx emissions by 50 percent in Colorado and New Mexico and would result in a NOx emission factor of 6.7 g/hp-hr in Colorado and 8.0 g/hp-hr in New Mexico." What is the basis for this assumption? The 2 g/hp-hr interim recommendation for new and replacement engines 300 hp and less (excluding engines less than 40 hp) has been in place since '05, which is almost 3 years ahead of the NSPS implementation date. Does the CE Workgroup have any information on how much impact this interim recommendation, as implemented through BLM/USFS APDs, has had on the average NOx emission factor from the current engine fleet in the 4 Corners area. Tables 6 and 7: Can some narrative be added that explains how emissions reductions are calculated and what each column in the tables represents? Why is table 6 (CO) different from table 7 (NM)? It is unclear how some of the emission reduction values have been calculated in tables 6 and 7. For example, in table 6 why is the emission reduction for < 100 Hp engines 130 TPY instead 143 TPY (50% x 286 TPY)?	Use of NSCR for NOx Control on Rich Burn Engines

Comment	Mitigation Option
1. Test data on small two-stroke NSCR retrofitted engines (Ajax DP-115) show NSCR can achieve large NOx emission reductions between 79% and 93% (Chapman, 2004a). On four stroke engines Chapman (2004b) indicates that "these catalyst systems reduce NOX emissions by over 98 percent, while reducing VOC by 80 percent and carbon monoxide by over 97 percent. NOx levels in the range of 0.1 to 1.0 g/bhp-hr have been achieved." Although this is consistent with the statement in the Draft Report that NSCR can achieve NOx emissions of less than 2 g/hp-hr, tighter control levels can certainly be achieved in retrofitting rich burn engines with a well controlled NSCR system. 2. Not all rich-burn engines would need to be retrofitted to NSCR to achieve the reductions postulated in the Draft Report. For example, if 57% of the under-100-hp engines in New Mexico were retrofitted with NSCR, which achieves less than 2 g/hp-hr NOx emissions (this is a conservative number, since NOx emissions that are well under 1 g/hp-hr are possible), then the overall emissions rate for that class of engine would decrease from 16 g/hp-hr to 8 g/hp-hr. According to Table 7 in the Draft Report, this would mitigate 6337 tons/yr of NOx (6694 tons/yr with growth). Since only 57% of the engines in this classification would need to be retrofitted, a retrofit kit would need to be developed only for the most common engine model (or a few models, at most.) This would save the expense of engineering development for engine models that have only a few examples represented in the Four Corners area and would concentrate the engineering effort where it would do the greatest amount of good. If more that 57% of the engines were controlled at the 2 g/hp-hr level, then more that 6337 tons/yr of NOx would be mitigated, but the incremental cost per tons/yr of NOx would be higher than that of the first 6337 tons/yr. It should also be noted that if the 57% of engines with NSCR controlled NOx at the 1 g/hp-hr rather than 2 g/hp-hr, 6773 tons/yr of NOx world be mitigated. This is an additional 436 tons/yr. A number of issues are identified with the use of NSRC on small engines. All of these issues, including ammonia formation, can be eliminated or minimized through use of a NSCR retrofit package that includes all the right components. The appropriate NSCR retrofit kit should include: - A 3-way catalytic converter - Exhaust oxygen sensor - Replace existing carburetor with a controllable air/fuel ratio (AFR) controller device. The ratio of an engine's actual AFR to the stoichiometric AFR for the fuel being used is referred to as the Lambda parameter. To ensure that exhaust bound O2 comprises no more that 0.5% (by volume) of the total engine exhaust, rich burn engines operate at λ's of between 0.988 and 0.992 (Chapman, 2004b). (For engines burning clean, dry natural gas, the air to fuel ratio (AFR) for stoichiometry is ~16.1:1, Chapman, 2004a). - Computerized control using feedback from the exhaust oxygen sensor to control the air/fuel ratio λ's of between 0.988 and 0.992 with the retrofitted NSCR system. - Exhaust gas recirculation (EGR) and controllable ignition timing could also be included and controlled by the same computer. Both EGR and retarded ignition timing reduce engine-out NOx emissions and enhance the effectiveness of the catalyst. Retarded ignition timing also has the effect of increasing exhaust temperature, which will improve the effectiveness of the catalyst at light engine	Use of NSCR for NOx Control on Rich Burn Engines

Comment	Mitigation Option
loads. Although considerable engineering effort is required to develop the retrofit kit, it needs to be done for only one engine model or a few engine models, at most. In the 3rd parg. under engines < 100 hp, it states; "Also, research indicates that if the AFR drifts off the optimal setting, then NOx emissions may be converted (on an equal basis) to ammonia. If this occurs within the discharge plume of an engine, it may accelerate the conversion of NOx emissions into particulate nitrate. This is the reason that the carburetor must be replaced with a more accurate AFR controller having feedback from an exhaust oxygen sensor. With such a system, accurate AFR control is achieved, and generation of ammonia is not an issue. ____ Chapman, K., 2004a, Report 6: Cost-Effective Reciprocating Engine Emissions Control and Monitoring for E&P Field and Gathering Engines, Technical Progress Report, DOE Award DE-FC26-02NT15464, Kansas State University, August Chapman, K., 2004b, Report 4: Cost-Effective Reciprocating Engine Emissions Control and Monitoring for E&P Field and Gathering Engines, Technical Progress Report, DOE Award DE-FC26-02NT15464, Kansas State University, January	
The assumption of 50% reduction of NOx in the Draft Report is too pessimistic or small. Other information indicates that NOx reduction greater than 90% is achievable. Another report indicated 95.9% NOx reduction on a 320 kW (430 hp) natural-gas fueled engine. The same report gave costs of $2,205-$3,684 per ton of NOx removed. This is considerably less than the $10,300 per ton of NOx removed indicated in the Draft Report. Another report indicated that the cost of SCR on reciprocating natural-gas engines varied from $30-$250 per horsepower with no correlation to engine size. Considering that the date of the fourth report is 1990, one reason for the variation in cost may be lack of experience on the part of some installers. Using the same methodology that was used in the Draft Report, but allowing a 90% NOx reduction on new engines instead of 50% gives a reduction of 1789 tons/year (16.5% reduction of overall NOx) in Colorado and a reduction of 2015 tons/year (4.6% reduction of overall NOx in New Mexico. The 90% NOx reduction should be achievable with good operation and maintenance practice in light of the 95.9% NOx reduction already achieved in the field. These figures were for new engines greater than 500 hp. Since the reported engine was smaller than 500 hp, the same calculation was performed for new engines greater than 300 hp. These gave a reduction of 2,109 tons/year (19.5%) in Colorado and 2502 tons/year (5.8%) in New Mexico. The engines with SCR would have NOx emissions of about 0.1 g/hp-hr. ____ 1. Jim McDonald and Xavier Palacios, "Compressor Tech 2: SCR for Gaz de France," Miratech Corporation, Tulsa, OK, December 1, 2002. 2. Johnson Matthey Corp., "Maximum NOx Control for Stationary Diesel and Gas Engines," brochure number "jm_brochure_scr_062306b.pdf". 3. Ravi Krishnan, RJM Corp., "Urea-based SCR technology achieves 12 ppm NOx on natural gas engine," PennWell Power Group Online Article available at http://pepei.pennet.com/Articles/Article_Display.cfm?ARTICLE_ID=156191,	Use of SCR for NOx Control on Lean Burn Engines

Comment	Mitigation Option
October 1, 2002. 4. G.S. Shareef and D.K. Stone, "Evaluation of SCR NOx controls for small natural gas-fueled prime movers. Phase 1. Topical Report," report number PB-90-270398/XAB; DCN-90-209-028-11; GRI-5089-254-1899, Radian Corp., Research Triangle Park, NC, July 1, 1990.	
The first paragraph of the section on Next Generation RICE Stationary Technology in the Draft Report does not give adequate weight to the importance of next generation technology. As emissions regulations become tighter (e.g., 0.2 g/hp-hr NOx in 2010), those limits will become increasingly difficult to meet with existing technology. Continuing research on advanced technologies is necessary to ensure than ever tighter limits in the future can be met. Three of the technologies listed below, NOx trap catalysts, laser ignition, and HCCI, are close to meeting the 0.2 g/hp-hr limit by themselves. Two of the technologies, laser ignition and HCCI, may be able to meet the 0.2 g/hp-hr limit without aftertreatment. With aftertreatments they may be able to meet an even lower limit. NOx trap catalysts are an aftertreatment that offers the same performance as SCR, but with potentially lower cost. Air separation membranes may be used in combination with other technologies to outperform the 0.2 g/hp-hr limit. NOx trap catalysts are similar in performance to SCR, that is they can reduce more than 90% of the engine-out NOx to achieve less than 1 g/hp-hr NOx emissions.[1] The estimates of NOx abatement used in the Cumulative Effects SCR section of the draft report may be used as a guide to the abatement potential of NOx trap catalysts. The cost is expected to be less than that of SCR because ammonia or urea is not used as a reductant. Instead, some of the fuel is used as a reductant. The increase in fuel consumption may be up to 8%, but is typically about 4%. Air separation membranes used to deplete oxygen from the intake air have an effect on NOx emissions that is similar to that of exhaust gas recirculation (EGR) in rich-burn and diesel engines. Combined with ignition retardation, a reduction in engine-out NOx of up to 40% can be expected.[2,3] For engines in the 300-500 hp range, air separation membranes with ignition retard could reduce overall NOx emissions to 2 g/hp-hr in both Colorado and New Mexico. For the 100-300 hp range, these technologies could reduce overall NOx emissions from 16.3 to 10 g/hp-hr in Colorado and from 12.5 to 7.5 g/hp-hr in New Mexico. For engines under 100 hp, the technologies could reduce overall NOx emissions from 13.4 to 8 g/hp-hr in Colorado and from 16 to 9.6 g/hp-hr. Laser ignition may be able to reduce NOx emissions by as much as 70% in lean burn engines.[4] However, in the reference cited, the baseline emissions for the engine with spark ignition were higher than the emissions that are currently achievable with lean burn engines. Additional development and testing will be required to verify the reduction of NOx emissions. There is little information in the literature about lean NOx catalysts used with lean burn natural gas engines. Information about lean NOx catalysts used with diesel engines indicates NOx reductions of 10-40% depending on whether fuel is used as a reductant.[5,6] NOx reductions for lean burn natural gas engines is expected to be similar. Although researchers are attempting to improve the conversion efficiency of lean NOx catalysts, their current low performance makes them unsuitable for the short term. Only a few experimental measurements of NOx from homogeneous-charge	Next Generation Stationary RICE Technology

Comment	Mitigation Option
compression-ignition (HCCI) engines have been reported. The measurements are typically reported as a raw NOx meter measurement in parts per million rather than being converted to grams per horsepower-hour. Dibble reported a baseline measurement of 5 ppm when operated on natural gas.[7] Green reported NOx emissions from HCCI-like (not true HCCI) combustion of 0.25 g/hp-hr.[8] Whether HCCI technology can be applied to all engine types and sizes is not known. In addition, the ultimately achievable NOx emissions from such engines is not known. However, if all reciprocating engines could be converted to HCCI so that the engines produce no more than 0.25 g/hp-hr, then the overall NOx emissions reduction would be 80% in both Colorado and New Mexico using the calculation methodology of the SCR mitigation option. ____________________ 1 James E. Parks II, Douglas Ferguson III, and John M. E. Storey, "NOx Reduction With Natural Gas for Lean Large-Bore Engine Applications Using Lean NOx Trap Aftertreatment." Oak Ridge National Laboratory, 2360 Cherahala Blvd., Oak Ridge, TN 37932. 2 K. Stork and R. Poola, "Membrane-Based Air Composition Control for Light-Duty Diesel Vehicles: A Cost and Benefit Assessment," Report Number ANL/ESD/TM-144, Argonne National Laboratory, 9700 South Cass Avenue, Argonne, IL 60439, October 1998. 3 Joe Kubsh, "Retrofit Emission Control Technologies for Diesel Engines," NAMVECC 2003, Manufacturers of Emission Controls Association, www.meca.org, Chattanooga, TN, November 4, 2003. 4 B. Bihari, S. B. Gupta, R. R. Sekar, J. Gingrich, and J. Smith, "Development of Advanced Laser Ignition System for Stationary Natural Gas Reciprocating Engines," ICEF2005-1325, ASME-ICE 2005 Fall Technical Conference, Ottawa, Canada, 2005. 5 Joe Kubsh, op.cit. 6 Carrie Boyer, Svetlana Zemskova, Paul Park, Lou Balmer-Millar, Dennis Endicott, and Steve Faulkner, "Lean NOx Catalysis Research and Development", Caterpillar Inc., presented at the 2003 Diesel Engine Engineering Research Conference. 7 Robert Dibble, et al, "Landfill Gas Fueled HCCI Demonstration System," CA CEC Grant No: PIR-02-003, Markel Engineering Inc. 8 Johney Green, Jr., "Novel Combustion Regimes for Higher Efficiency and Lower Emissions," Oak Ridge National Laboratory, "Brown Bag" Luncheon Series, December 16, 2002.	
The SUGF recommends further examination of the above listed mitigation options as particulates associated with each option contribute to local visibility issues.	Automation of Wells to Reduce Truck Traffic Reduced Truck Traffic by Centralizing Produced Water Storage Facilities

Monitoring

MONITORING: PREFACE

Overview
The charter for the Monitoring Workgroup was as follows:

> "The monitoring workgroup will review information provided on existing monitoring networks, and then identify data gaps and options for additional monitoring in cooperation with the other work groups. A gap analysis and trends analysis will be the basis for identifying options for additional monitoring. The monitoring workgroup will identify potential funding sources and develop a holistic monitoring strategic plan for the region."

Group Membership
The Monitoring Group was quite diverse. Members included private citizens from the Durango-Cortez-Aztec area, National Park Service personnel, U. S. Forest Service personnel, the Director of Research and Education at Mountain Studies Institute, a University of Denver graduate student, Tribal air quality personnel (Southern Ute and Navajo Nation), a private consulting hydrologist, air quality staff from two state agencies (New Mexico and Colorado), and personnel from two EPA regions (VI and VIII), among others.

Scope of Work
The following scope of work, including "specific tasks" and "discussion" for the Monitoring Group, was established at the onset of the Task Force.

Specific Tasks
D. Identify existing monitoring networks located in the Four Corners study area. Review information provided by these networks to identify data gaps.
E. Conduct data analyses to determine pollutant trends within the Four Corners study area.
F. Using the gap analysis and trend analysis, identify options for additional monitoring.
G. Incorporate public input when developing a monitoring strategy.
H. Identify potential funding sources for additional monitoring sites.
I. Develop final monitoring strategies for the Four Corners study area.

Discussion
The work group examined the various agency monitoring networks to determine present monitor locations and types, and pollutants or parameters being measured. Using this evaluation the work group identified locations within the study area that lack adequate representation in terms of pollutant data. Available data from the monitoring networks were analyzed to establish pollutant trends. The method and extent of establishing additional monitoring capabilities was dictated by the results from the network studies and from the data analyses. Public input was also addressed during the consideration of potential monitoring site locations. Once it had been established where monitoring sites were needed and what pollutants or parameters were to be measured, the work group identified potential funding sources.

Task 1
In identifying the existing monitoring networks located in the Four Corners study area, a matrix was developed. The matrix attempted to list all known air pollutant monitoring sites and meteorological monitoring sites within the study area. The type of site and the parameters measured at that site were listed in the matrix. The matrix was comprised of four spreadsheets; one having "site information", one having the "criteria sites", one having the "deposition sites", and one having the "meteorological sites".

Task 2
Data from agency databases were used to generate wind and pollution roses, and to generate graphs of pollutant trends. "Overlays" of pollution roses on both political boundary maps and on topographic maps have been produced. The trend graphs plot various pollutant concentrations since 1990.

Task 3
Once the gap analysis and the data analyses had been conducted, the work group assessed the types of monitors required and optimal site locations in the Four Corners study area.

Task 4

Because public sentiment and concern regarding air quality was of great importance to the Four Corners Air Quality Task Force, available public input was considered prior to any final suggestions of site location and type. Some of this input came from public citizens who are part of the task force.

Task 5

To provide the public with some idea of what it takes to set up a new monitoring site, two spreadsheets were created to show both capital and operating costs of two different agency sites. The work group identified potential funding sources for additional monitoring sites.

Task 6

A variety of monitoring strategies/suggestions were developed. These included ozone and ozone precursors, mercury, nitrate and sulfate, and visibility.

EXISTING MONITORING NETWORKS

Monitoring Site Matrix Narrative

The Four Corners Area Monitoring Site Matrix is an attempt to list all of the various air quality monitoring sites in the Four Corners area as well as the predominant meteorological monitoring sites. The following explanations refer to the major column headers of the various matrix pages.

Monitoring Programs

All of the air quality programs are represented in the matrix (some sites are under multiple programs) and are listed below. The following descriptions of the programs are from each program's web site:

ARM-FS: Air Resource Management, USDA Forest Service

The Real-Time Images section features live images and current air quality conditions from USDA-FS monitoring locations throughout the United States. Digital images from Web-based cameras are updated every 15 to 60 minutes. Near real-time air quality data and meteorological data are also provided to distinguish natural from human-made causes of poor visibility, and to provide current air pollution levels to the public.

CASTNET: Clean Air Status and Trends Network, EPA

CASTNET provides atmospheric data on the dry deposition component of total acid deposition, ground-level ozone and other forms of atmospheric pollution. CASTNET is considered the nation's primary source for atmospheric data to estimate dry acidic deposition and to provide data on rural ozone levels. Used in conjunction with other national monitoring networks, CASTNET can help determine the effectiveness of national emission control programs.

Each CASTNET dry deposition station measures:

- weekly average atmospheric concentrations of sulfate, nitrate, ammonium, sulfur dioxide, and nitric acid;
- hourly concentrations of ambient ozone levels; and
- meteorological conditions required for calculating dry deposition rates.

CoAgMet: Colorado Agricultural Meteorological Network

In the early 1990's, two groups on the Colorado State campus, the Plant Pathology extension specialists and USDA's Agricultural Research Service (ARS) Water Management Unit, discovered that they had a mutual interest in collecting localized weather data in irrigated agricultural area. Plant pathology used the data for prediction of disease outbreaks in high value crops such as onions and potatoes, and ARS used almost the same information to provide irrigation scheduling recommendations.

To leverage their resources, these two formed an informal coalition, and invited others in the ag research community to provide input into the kinds and frequency of measurements that would be most useful to a broad spectrum of agricultural customers. A standardized set of instruments was selected, a standard datalogger program was developed, and a fledgling network of some eight stations was established in major irrigated areas of eastern Colorado. As interest grew and funds were made available, primarily from potential users, more stations were added.

Initially, stations were located near established phone service to allow daily collection of data. Soon, cellular phone service began to become widely available, and the group determined that this methodology was a reliable and inexpensive method of data recovery. Commercial software was used to download data from the growing list of stations shortly after midnight to a USDA-ARS computer, from which it was then distributed to interested users via answering machine, automated FAX and satellite downlink (Data Transmission Network).

As the network grew, Colorado Climate Center at Colorado State became interested in these data, and subsequently took over the daily data collection and quality assessment. CCC added internet delivery and a wide range of data delivery options, and continues to improve the user interface in response to a growing interest in these data.

IMPROVE: Interagency Monitoring of Protected Visual Environments

Recognizing the importance of visual air quality, Congress included legislation in the 1977 Clean Air Act to prevent future and remedy existing visibility impairment in Class I areas. To aid the implementation of this legislation, the IMPROVE program was initiated in 1985. This program implemented an extensive long term monitoring program to establish the current visibility conditions, track changes in visibility and determine causal mechanism for the visibility impairment in the National Parks and Wilderness Areas.

NADP/NTN: National Atmospheric Deposition Program, National Trends Network
The National Atmospheric Deposition Program/National Trends Network (NADP/NTN) is a nationwide network of precipitation monitoring sites. The network is a cooperative effort between many different groups, including the State Agricultural Experiment Stations, U.S. Geological Survey, U.S. Department of Agriculture, and numerous other governmental and private entities. The NADP/NTN has grown from 22 stations at the end of 1978, our first year, to over 250 sites spanning the continental United States, Alaska, and Puerto Rico, and the Virgin Islands.

The purpose of the network is to collect data on the chemistry of precipitation for monitoring of geographical and temporal long-term trends. The precipitation at each station is collected weekly according to strict clean-handling procedures. It is then sent to the Central Analytical Laboratory where it is analyzed for hydrogen (acidity as pH), sulfate, nitrate, ammonium, chloride, and base cations (such as calcium, magnesium, potassium and sodium).

NADP/MDN: National Atmospheric Deposition Program, Mercury Deposition Network
The Mercury Deposition Network (MDN), currently with over 90 sites, was formed in 1995 to collect weekly samples of precipitation which are analyzed by a prominent laboratory for total mercury. The objective of the MDN is to monitor the amount of mercury in precipitation on a regional basis; information crucial for researchers to understand what is happening to the nation's lakes and streams.

NWS: National Weather Service
Feb. 9, 2005 - The NOAA National Weather Service is celebrating its 135th anniversary amid a renewed commitment to preserve its history.

On February 9, 1870, President Ulysses S. Grant signed a joint resolution of Congress authorizing the Secretary of War to establish a national weather service. Later that year, the first systematized, synchronous weather observations ever taken in the U.S. were made by "observer sergeants" of the Army Signal Service.

Today, thousands of weather observations are made hourly and daily by government agencies, volunteer/citizen observers, ships, planes, automatic weather stations and earth-orbiting satellites.

"Since the beginning, the mission of the National Weather Service to protect life and property has been and remains to be the top priority," said Brig. Gen. David L. Johnson, U.S. Air Force (Ret.), director of NOAA's National Weather Service. "Advances in research and technology through the decades have allowed the NOAA National Weather Service to create an expanding observational and data collection network that tracks Earth's changing systems."

RAWS: Remote Automated Weather Stations
There are nearly 2,200 interagency Remote Automated Weather Stations (RAWS) strategically located throughout the United States. These stations monitor the weather and provide weather data that assists land management agencies with a variety of projects such as monitoring air quality, rating fire danger, and providing information for research applications.

SLAMS: State/Local Air Monitoring Stations
These ambient air monitoring sites are designated by EPA as State/Local Air Monitoring Stations (SLAMS). Pollutants monitored are the criteria pollutants, and include ozone, particulate matter, carbon monoxide, lead, sulfur dioxide, and oxides of nitrogen.

SPMS: Special Purpose Monitoring Stations
Special Purpose Monitoring Stations provide for special studies needed by the State and local agencies to support State implementation plans and other air program activities. The SPMS are not permanently established and, can be adjusted easily to accommodate changing needs and priorities. The SPMS are used to supplement the fixed monitoring network as circumstances require and resources permit. If the data from SPMS are used for SIP purposes, they must meet all QA and methodology requirements for SLAMS monitoring.

Tribal: Tribal Jurisdiction
These sites are under tribal jurisdiction and are the tribal equivalent to SLAMS sites, monitoring the same criteria pollutants.

Period of Record
The period of record refers to how long a site has been in operation. In some cases, dates refer to monitoring of major parameters at a site.

In the case of the NWS sites, the "start" dates are the dates when the NWS data was inserted into the MesoWest database which is maintained by the University of Utah's Department of Meteorology.

Distance From
The distances listed refer to the distance from each monitoring site to two representative Four Corners cities; one in Colorado and one in New Mexico. The distances were obtained either from Argonne National Lab's interactive Four Corners Aerometric Map or Google Maps. Other "site-to-city" distances can be determined by using either map.

Criteria Pollutants
EPA uses six "criteria pollutants" as indicators of air quality, and has established for each of them a maximum concentration above which adverse effects on human health may occur. Explanations of these pollutants can be found on EPA's "Green Book" website,
http://www.epa.gov/oar/oaqps/greenbk/o3co.html

Meteorological
These columns indicate what meteorological parameters are monitored at a given site. The parameters are: wind (usually speed and direction), temperature (usually 2-meter and 10-meter), delta T (the difference between 2-meter and 10-meter), solar radiation, relative humidity, and precipitation.

Deposition
The parameters refer to those monitored by The National Atmospheric Deposition Program/National Trends Network (NADP/NTN).

The passive ammonia sampling sites are also listed on the "Deposition" page.

Key to Matrix Symbols
The following explanation refers to the various symbols used within the matrix cells.

h: Sampled and/or averaged hourly
1d/3d: Sampled once every three days
1d/6d: Sampled once every six days
w: Sampled weekly
3w: Sampled every three weeks

Monitoring Site General Information

Site	Program	Address	AQS / Other Code	Period of Record From	Period of Record To	Latitude	Longitude	Elevation (meters)	Distance from: (Km) Farmington	Distance from: (Km) Durango
Substation	SLAMS	16 mi. NW of Farmington, NM	35-045-1005	01/01/72	Present	36.7967	-108.4803	1643	24.2	73.9
Bloomfield	SLAMS	162 Highway 550 ; Bloomfield, NM	35-045-0009	08/01/77	Present	36.7421	-107.9773	1618	19.4	59.8
Navajo Lake	SLAMS	423 Highway 539 ; Navajo Lake, NM	35-045-0018	07/01/05	Present	36.8098	-107.6514	1950	49.3	56.4
Farmington	SLAMS	724 W Animas ; Farmington, NM	35-045-0006	08/01/77	Present	36.7273	-108.2152	1643	0.0	66.7
S.Ute 3 - Bondad	Tribal	7571 Highway 550 ; La Plata County, CO	08-067-7003	04/01/97	Present	37.1025	-107.8703	1920	50.5	19.3
S.Ute 1 - Ignacio	Tribal	County Road 517 ; La Plata County, CO	08-067-7001	06/01/82	Present	37.1389	-107.6317	1981	67.7	25.8
Shamrock Site	ARM-FS IMPROVE	8 mi. NE of Bayfield, CO	08-067-9000 SHMI1	02/01/04 08/01/04	Present Present	37.3038	-107.4842	2351	90.3	34.3
Mesa Verde	CASTNET IMPROVE SPMS NADP/NTN NADP/MDN	Chapin Mesa, Mesa Verde Nat'l Park, Montezuma County, CO	MEV405 MEVE 1 08-038-0101 CO99 CO99	01/10/95 03/05/94 07/23/06 04/28/81 12/26/01	Present Present Present Present Present	37.1984	-108.4907	2165	57.1	54.3
Pagosa Springs – School	SLAMS	309 Lewis St., Pagosa Springs, CO	08-007-0001	08/01/75	Present	37.2681	-107.0211	2168	121.9	74.8
Durango – Courthouse	SLAMS	1060 E. 2nd Ave., Durango, CO	08-067-1001	03/01/87	12/31/06	37.2739	-107.8786	1984	66.9	0.1
Durango – River City	SLAMS	1235 Camino del Rio, Durango, CO	08-067-0004	09/01/85	Present	37.2769	-107.8806	1985	66.8	0.3
Durango – Tradewinds	SLAMS	1455 S. Camino del Rio, Durango, CO	08-067-0009	10/30/03	04/06/05	37.2187	-107.8516	1973	63.1	3.9
Durango – Cutler	SLAMS	177 Cutler Dr., Durango, CO	08-067-0010	10/30/03	04/30/06	37.3082	-107.8456	1992	70.9	4.3
Durango – Grandview	SLAMS	56 Davidson Rd., Durango, CO	08-067-0011	07/01/04	12/31/06	37.2295	-107.8267	2044	67.6	6.8
Telluride	SLAMS	333 W. Colorado Ave., Telluride, CO	08-113-0004	03/01/90	Present	37.9375	-107.8117	2694	140.6	76.3
Durango Mt. Resort	Other	Hwy. 550 & Purgatory Drive	---	10/11/02	Present	37.6314	-107.8076	2665	105.1	38.9
Wolf Creek Pass	NADP/NTN	Mineral County, CO	CO91	05/26/92	Present	37.4686	-106.7903	3292	148.8	98.6
Molas Pass	NADP/NTN	San Juan County, CO	CO96	07/29/86	Present	37.7514	-107.6853	3249	121.2	56.4

Site	Program	Address	AQS / Other Code	Period of Record From	Period of Record To	Latitude	Longitude	Elevation (meters)	Distance from: (Km) Farmington	Distance from: (Km) Durango
Weminuche	IMPROVE	30 mi. N of Durango, CO	WEMI1	03/02/88	Present	37.6594	-107.7999	2750	110.6	44.0
San Pedro Parks	IMPROVE	6 mi E of Cuba, NM	SAPE1	08/15/00	Present	36.0139	-106.8447	2935	133.6	160.4
Fort Defiance	Tribal	Rte. 12 N, Bldg. F-004-051, Fort Defiance, AZ	04-001-1234	01/01/99	Present	35.7460	-109.0717	2090	135.4	200.4
Shiprock Dine College	Tribal	Dine College, GIS Lab, Shiprock, NM	35-045-1233	01/01/03	Present	36.8071	-108.6952	1525	45.0	141.1
Canyonlands NP	CASTNET NADP/NTN IMPROVE	"Island of the Sky" Visitor's Center, Canyonlands Nat'l Park, San Juan County, UT	CAN407 UT09 CANY1	01/24/95 11/11/97 03/02/88	Present Present Present	38.4580	-109.821	1814	239.8	214.6
Arches NP	IMPROVE	14 mi N of Moab, UT	ARCH1	03/02/88	05/16/92	38.7833	-109.5830	1722	253.6	217.2
Moab #6	SLAMS	168 West 400 North, Moab, UT	49-019-0006	10/21/93	6/30/03	38.5795	-109.5540			
Petrified Forest NP (Old)	CASTNET IMPROVE SPMS	1 mi. N of park HQ	PET427 PEFO1 04-001-0012	? 03/02/88 10/27/86	Present Present 04/16/92	35.0772	-109.7697	1766	262.9	329.2
Petrified Forest NP (New)	SPMS	SW Entrance; off Rte. 180	04-017-0119	01/01/88	Present	34.8230	-109.8919	1723	265.5	331.5
Rainbow Forest NP	NADP/NTN	Apache County, AZ	AZ97	12/03/02	Present	35.0013	-109.0128	1707	207.5	274.1
Alamosa	NADP/NTN	Alamosa county, CO	CO00	04/22/80	Present	37.4414	-105.8653	2298	221.0	177.6
Great Sand Dunes NP	IMPROVE	Monument HQ, Saguache County, CO	GRSA1	05/04/88	Present	37.7249	-105.5185	2498	258.0	207.1
Big Horn	RAWS	Conejos County, CO	BHRC2	05/13/93	Present	37.0208	-106.2011	2637	175	147
Sand Dunes	RAWS	Alamosa County, CO	SDNC2	06/02/04	Present	37.7267	-105.5108	2537	254	210
Lujan	RAWS	Saguache County, CO	LUJC2	09/13/94	Present	38.2544	-106.5678	3400	214	155
Needle Creek	RAWS	Saguache County, CO	NCKC2	09/05/02	Present	38.3894	-106.5308	2741	227	168
Huntsman Mesa	RAWS	Gunnison County, CO	HMEC2	05/22/91	Present	38.3319	-107.0889	2865	195	135
McClure Pass	RAWS	Gunnison County, CO	MPRC2	06/11/85	Present	39.1267	-107.2842	2761	264	205
Taylor Park	RAWS	Gunnison County, CO	TAPC2	10/27/87	Present	38.9086	-106.6028	3200	268	210
PSF2 Salida 555	RAWS	Chaffee County, CO	SIDC2	05/01/97	Present	38.7856	-105.9569	2932	291	229
Red Deer	RAWS	Chaffee County, CO	RDKC2	05/01/83	Present	38.8272	-106.2117	2660	280	218
Jay	RAWS	Delta County, CO	JAYC2	07/09/84	Present	38.8456	-107.7386	1890	227	168
Blue Park	RAWS	Mineral County, CO	BLPC2	04/24/90	Present	37.7931	-106.7786	3179	167	109
Black Canyon	RAWS	Montrose County, CO	LPRC2	06/04/97	Present	38.5428	-107.6869	2609	195	132
Carpenter Ridge	RAWS	Montrose County, CO	CPTC2	12/17/98	Present	38.4594	-109.0469	2465	195	160
Cottonwood Basin	RAWS	Montrose County, CO	CMEC2	05/23/91	Present	38.5731	-108.2778	2201	194	140

Site	Program	Address	AQS / Other Code	Period of Record		Latitude	Longitude	Elevation (meters)	Distance from: (Km)	
				From	To				Farmington	Durango
Nucla	RAWS	Montrose County, CO	NUCC2	05/21/98	Present	38.2333	-108.5617	1786	162	116
Sanborn Park	RAWS	Montrose County, CO	SPKC2	01/29/85	Present	38.1922	-108.2169	2417	153	101
Salter	RAWS	Dolores County, CO	SAWC2	05/30/85	Present	37.6511	-108.5369	2500	101	67
Devil Mtn.	RAWS	Archuleta County, CO	DYKC2	07/27/89	Present	37.2269	-107.3053	2274	92	50
Sandoval Mesa	RAWS	Archuleta County, CO	SDVC2	07/15/99	Present	37.0994	-107.3028	2588	86	53
Big Bear Park	RAWS	La Plata County, CO	BBRC2	08/26/05	Present	37.4961	-107.7294	3170	90	28
Mesa Mtn.	RAWS	La Plata County, CO	MMRC2	11/17/93	Present	37.0564	-107.7086	2249	54	25
SJF1 Durango 555	RAWS	La Plata County, CO	DUFC2	06/01/96	Present	37.3517	-107.9000	2502	72	9
Chapin	RAWS	Montezuma County, CO	CHAC2	09/07/99	Present	37.1994	-108.4892	2172	55	51
Mockingbird	RAWS	Montezuma County, CO	MOKC2	08/24/05	Present	37.4744	-108.8842	1957	99	87
Morefield	RAWS	Montezuma County, CO	MRFC2	11/12/99	Present	37.2972	-108.4128	2383	61	45
Albino Canyon	RAWS	San Juan County, NM	CWRN5	09/27/83	Present	36.9769	-107.6283	2182	55	35
Washington Pass	RAWS	San Juan County, NM	WPSN5	11/19/03	Present	36.0781	-108.8575	2856	86	147
Coyote	RAWS	Rio Arriba County, NM	COYN5	08/07/96	Present	36.0667	-106.6472	2682	149	161
Deadman Peak	RAWS	Rio Arriba County, NM	DPKN5	05/23/00	Present	36.4231	-107.7719	2575	46	129
Dulce #2	RAWS	Rio Arriba County, NM	DLCN5	07/07/05	Present	36.9350	-107.0000	2070	107	79
Jarita Mesa	RAWS	Rio Arriba County, NM	JARN5	04/15/02	Present	36.5558	-106.1031	2683	183	168
Stone Lake	RAWS	Rio Arriba County, NM	STLN5	07/07/05	Present	36.7314	-106.8647	2268	115	103
Zuni Buttes	RAWS	McKinley County, NM	ZNRN5	04/04/06	Present	35.1392	-108.9414	2039	172	236
Alb Portable #2	RAWS	McKinley County, NM	TSO43	11/18/03	Present	35.5264	-107.3211	2481	138	182
Bryson Canyon	RAWS	Grand County, UT	BCRU1	09/03/87	Present	39.2789	-109.2211	1621	283	241
Big Indian Valle	RAWS	San Juan County, UT	BIVU1	09/02/87	Present	38.2244	-109.2783	2121	182	153
Kane Gulch	RAWS	San Juan County, UT	KAGU1	06/20/91	Present	37.5247	-109.8931	1981	165	174
North Long Point	RAWS	San Juan County, UT	NLPU1	08/13/97	Present	37.8547	-109.8389	2646	182	175
Piney Hill	RAWS	Apache County, AZ	QPHA3	11/19/03	Present	35.7611	-109.1675	2469	126	187
Cortez	CoAgMet	9 mi. SW of Cortez, CO	CTZ01	04/24/91	Present	37.2248	-108.6730	1833	67	67
Dove Creek	CoAgMet	4 mi. NW of Dove Creek	DVC01	10/28/92	Present	37.7265	-108.9540	2010	123	104
Towaoc	CoAgMet	Ute Mtn Ute Farm	TWC01	06/30/98	Present	37.1891	-108.9350	1621	78	88
Yellow Jacket	CoAgMet	2.5 mi. NW of Yellow Jacket	YJK01	05/19/91	Present	37.5289	-108.7240	2103	94	77
Yucca House	CoAgMet	Yucca House National Monument	YUC01	01/01/02	Present	37.2478	-108.6870	1821	69	67
Cortez-Montezuma County Airport	NWS	3 mi. SW of Cortez, CO	KCEZ	01/01/97	Present	37.3064	-108.6256	1803	71	7

Site	Program	Address	AQS / Other Code	Period of Record		Latitude	Longitude	Elevation (meters)	Distance from: (Km)	
				From	To				Farmington	Durango
Cottonwood Pass	NWS	SW of Buena Vista, CO	K7BM	11/17/04	Present	38.7825	-106.2181	2995	280	215
Durango-La Plata County Airport	NWS	1000 Airport Road; Durango, CO	KDRO	01/01/97	Present	37.1431	-107.7597	2038	60	0
Gunnison-Crested Butte Regional Airport	NWS	519 W Rio Grande; Gunnison, CO	KGUC	01/01/97	Present	38.5333	-106.9333	2340	221	156
Montrose Regional Airport	NWS	2100 Airport Road ; Montrose, CO	KMTJ	01/01/97	Present	38.5050	-107.8975	1755	189	128
Pagosa Springs, Wolf Creek Pass	NWS	NE of Pagosa Springs, CO	KCPW	11/11/03	Present	37.4514	-106.8003	3584	145	95
Saguache Municipal Airport	NWS	2 mi. NW of Saguache, CO	04V	11/17/04	Present	38.0972	-106.1686	2385	227	171
Salida Mountain, Monarch Pass	NWS	W of Salida, CO	KMYP	09/10/03	Present	38.4844	-106.3169	3667	249	185
Telluride Regional Airport	NWS	1500 Last Dollar Road ; Telluride, CO	KTEX	02/05/97	Present	37.9539	-107.9086	2767	135	72
Farmington, Four Corners Regional Airport	NWS	800 Municipal Drive ; Farmington, NM	KFMN	01/01/97	Present	36.7436	-108.2292	1677	0	63
Grants-Milan Municipal Airport	NWS	3 mi. NW of Grants, NM	KGNT	04/11/97	Present	35.1653	-107.9022	1988	160	214
Gallup Municipal Airport	NWS	2111 W Hwy 66 ; Gallup, NM	KGUP	01/01/97	Present	35.5111	-108.7894	1973	133	194
Window Rock Airport	NWS	1 mi. S of Window Rock AZ	KRQE	11/14/99	Present	35.6500	-109.0667	2055	131	190
Moab, Canyonlands Field	NWS	18 mi. NW of Moab, UT	KCNY	01/01/97	Present	38.7600	-109.7447	1388	249	224

ARM-FS : Air Resource Management, USDA Forest Service
CASTNET : Clean Air Status and Trends Network, EPA
CoAgMet : Colorado Agricultural Meteorological Network
IMPROVE : Interagency Monitoring of Protected Visual Environments
NADP/NTN : National Atmospheric Deposition Program, National Trends Network
NADP/MDN : National Atmospheric Deposition Program, Mercury Deposition Network
NWS : National Weather Service
RAWS : Remote Automated Weather Stations
SLAMS : State/Local Air Monitoring Stations
SPMS : Special Purpose Monitoring Stations
Tribal : Tribal Jurisdiction

Criteria Pollutant Sites

Site	Program	Criteria Pollutants							
		O3	SO2	CO	NOx	NO	NO2	PM10	PM2.5
Substation	SLAMS	h	h		h	h	h		
Bloomfield	SLAMS	h	h		h	h	h		
Navajo Lake	SLAMS	h			h	h	h		h
Farmington	SLAMS							1d/6d	1d/3d
S.Ute 3 - Bondad	Tribal	h			h	h	h	ended 9/30/06	
S.Ute 1 - Ignacio	Tribal	h		h	h	h	h	ended 9/30/06	
Shamrock Site	ARM-FS IMPROVE	h	1d/3d		h 1d/3d	h	h	1d/3d	1d/3d
Mesa Verde	CASTNET IMPROVE SPMS NADP/NTN ADP/MDN	h	h 1d/3d		h 1d/3d			1d/3d	1d/3d
Pagosa Springs – School	SLAMS							1d/1d	1d/3d end 12/06
Durango – Courthouse	SLAMS							1d/3d end 12/06	
Durango- River City	SLAMS							1d/3d	
Durango – Tradewinds	SLAMS							1d/6d end 3/05	
Durango – Cutler	SLAMS							1d/6d end 4/06	
Durango - Grandview	SLAMS							1d/3d end 12/06	
Telluride	SLAMS							1d/3d	1d/3d end 12/06
Durango Mt. Resort	Other							h	
Weminuche	IMPROVE							1d/3d	1d/3d
San Pedro Parks	IMPROVE							1d/3d	1d/3d
Fort Defiance	Tribal							1d/6d	
Shiprock Dine College	Tribal							1d/6d	
Canyonlands NP	CASTNET NADP/NTN IMPROVE	h	h 1d/3d		h 1d/3d			1d/3d	1d/3d
Arches NP	IMPROVE		1d/3d		1d/3d				
Moab #6	SLAMS							1d/6d	
Petrified Forest NP (Old)	CASTNET IMPROVE SPMS	h h	h 1d/3d		h 1d/3d			1d/3d	1d/3d
Petrified Forest NP (New)	SPMS	h							
Great Sand Dunes NP	IMPROVE							1d/3d	1d/3d

See Monitoring Site General Information table for abbreviations
h : Sampled and/or averaged hourly
1d/1d : 24-hour sample taken every day
1d/3d : 24-hour sample taken every 3rd day
1d/6d : 24-hour sample taken every 6th day

Meteorological Sites

Site	Program	Wind	Temp	Delta T	Solar	RH	Precip
Substation	SLAMS	h	h	h	h		
Bloomfield	SLAMS	h	h	h	h		
Navajo Lake	SLAMS	h	h	h	h		
S.Ute 3 - Bondad	Tribal	h	h	h	h	h	h
S.Ute 1 - Ignacio	Tribal	h	h	h	h	h	h
Shamrock Site	ARM-FS IMPROVE	h	h		h	h	h
Mesa Verde	CASTNET IMPROVE SPMS NADP/NTN NADP/MDN	h	h	h	h	h	
Durango Mt. Resort	Other	h	h	h	h	h	h
Fort Defiance	Tribal	h	h		h	h	h
Shiprock Dine College	Tribal	h	h		h	h	h
Canyonlands NP	CASTNET NADP/NTN IMPROVE	h	h	h	h	h	
Petrified Forest NP (Old)	CASTNET IMPROVE	h	h	h	h	h	
Petrified Forest NP (New)	SPMS	h	h				
Big Horn	RAWS	h	h		h	h	h
Sand Dunes	RAWS	h	h		h	h	h
Lujan	RAWS	h	h		h	h	h
Needle Creek	RAWS	h	h		h	h	h
Huntsman Mesa	RAWS	h	h		h	h	h
McClure Pass	RAWS	h	h		h	h	h
Taylor Park	RAWS	h	h		h	h	h
PSF2 Salida 555	RAWS	h	h		h	h	h
Red Deer	RAWS	h	h		h	h	h
Jay	RAWS	h	h		h	h	h
Blue Park	RAWS	h	h		h	h	h
Black Canyon	RAWS	h	h		h	h	h
Carpenter Ridge	RAWS	h	h		h	h	h
Cottonwood Basin	RAWS	h	h		h	h	h
Nucla	RAWS	h	h		h	h	h
Sanborn Park	RAWS	h	h		h	h	h
Salter	RAWS	h	h		h	h	h
Devil Mtn.	RAWS	h	h		h	h	h
Sandoval Mesa	RAWS	h	h		h	h	h
Big Bear Park	RAWS	h	h		h	h	h
Mesa Mtn.	RAWS	h	h		h	h	h
SJF1 Durango 555	RAWS	h	h		h	h	h
Chapin	RAWS	h	h		h	h	h
Mockingbird	RAWS	h	h		h	h	h
Morefield	RAWS	h	h		h	h	h

Site	Program	Wind	Temp	Delta T	Solar	RH	Precip
Albino Canyon	RAWS	h	h		h	h	h
Washington Pass	RAWS	h	h		h	h	h
Coyote	RAWS	h	h		h	h	h
Deadman Peak	RAWS	h	h		h	h	h
Dulce #2	RAWS	h	h		h	h	h
Jarita Mesa	RAWS	h	h		h	h	h
Stone Lake	RAWS	h	h		h	h	h
Zuni Buttes	RAWS	h	h		h	h	h
Alb Portable #2	RAWS	h	h		h	h	h
Bryson Canyon	RAWS	h	h		h	h	h
Big Indian Valle	RAWS	h	h		h	h	h
Kane Gulch	RAWS	h	h		h	h	h
North Long Point	RAWS	h	h		h	h	h
Piney Hill	RAWS	h	h		h	h	h
Cortez	CoAgMet	h	h		h	h	
Dove Creek	CoAgMet	h	h		h	h	
Towaoc	CoAgMet	h	h		h	h	
Yellow Jacket	CoAgMet	h	h		h	h	
Yucca House	CoAgMet	h	h		h	h	
Cortez-Montezuma County Airport	NWS	h	h			h	
Cottonwood Pass	NWS	h	h			h	
Durango-La Plata County Airport	NWS	h	h			h	
Gunnison-Crested Butte Regional Airport	NWS	h	h			h	
Montrose Regional Airport	NWS	h	h			h	
Pagosa Springs, Wolf Creek Pass	NWS	h	h			h	
Saguache Municipal Airport	NWS	h	h			h	
Salida Mountain, Monarch Pass	NWS	h	h			h	
Telluride Regional Airport	NWS	h	h			h	
Farmington, Four Corners Regional Airport	NWS	h	h			h	
Grants-Milan Municipal Airport	NWS	h	h			h	
Gallup Municipal Airport	NWS	h	h			h	
Window Rock Airport	NWS	h	h			h	
Moab, Canyonlands Field	NWS	h	h			h	

See Monitoring Site General Information table for abbreviations
h: Sampled and/or averaged hourly

Deposition Sites

Site	Program	Deposition								
		NH3	**pH**	**SO4**	**NH4**	**NO3**	**Pb**	**HF**	**Hg**	**Ca, Mg, K, Na, Cl**
Substation	SLAMS	3w								
Navajo Lake	SLAMS	3w								
S.Ute 3 - Bondad	Tribal	3w								
Mesa Verde	CASTNET IMPROVE SPMS NADP/NTN NADP/MDN	3w	w	w	w	w			w	w w
Wolf Creek Pass	NADP/NTN		w	w	w	w				w
Molas Pass	NADP/NTN		w	w	w	w				w
Canyonlands NP	CASTNET NADP/NTN IMPROVE		w	w	w	w				w
Rainbow Forest NP	NADP/NTN		w	w	w	w				w
Alamosa	NADP/NTN		w	w	w	w				w
Farmington Airport	OTHER	3w								

See Monitoring Site General Information table for abbreviations
w : Sampled weekly
3w : Sampled every 3 weeks

DATA ANALYSIS AND RECOMMENDATIONS

Meteorology and Wind Roses

Background:

Rationale and Benefits:
Meteorology is the science that deals with the study of the atmosphere and its phenomena, especially with weather and weather forecasting. Meteorological conditions are a driving force in many bad pollution events and situations. These include stagnation, inversions and blowing dust. There are a number of components to meteorology, including wind speed, wind direction, temperature, relative humidity, barometric pressure, solar radiation, precipitation and others. Modeling is performed with the various components as part of forecasting for weather conditions as well as for air pollution impacts.

For air pollution, wind speed and wind direction are two of the more important components. These can determine how far pollution can be transported in a certain time period, if stagnation periods exist and what sources may have contributed to the air pollution. Wind roses are a simple visual way to depict wind speed strengths as a function of wind direction for a period of time. Wind roses are based on the direction that the wind is blowing from. Another way of visualizing a wind rose is to picture yourself standing in the center of the plot and facing into the wind. The wind direction is broken down in the 16 cardinal directions (i.e. N, NNE, NE, ENE, E, ESE, SE, SSE, S, etc). The wind speed is broken down into multiple ranges. The length of each arm of the wind rose represents the percentage of time the wind was blowing from that direction. The longer the arm, the greater percentage of time the wind is blowing from that direction. Since the occurrence of wind speeds of different ranges from a particular direction are stacked on the radius in order of increasing speeds, one must compare the length of each color to the distance between the percent circles to get the percent of time each range of wind speed occurred. The circles representing the percent of time can vary from rose to rose hence each rose must be checked for the values. Wind roses can be generated by a number of commercially available software programs. For this analysis, WRPLOT View from Lakes Environmental Software was employed.[1]

Existing meteorological data for the Four Corners region:
Meteorological data are collected at a number of different locations in the Four Corners region. Sites include State and Tribal agencies, the National Weather Service (NWS), the U.S. Forest Service (USFS), the National Park Service (NPS), The Remote Automated Weather Stations (RAWS) network, the Colorado Agriculture Meteorological Network (CoAgMet) and other private groups. Data are available from varying sources, including the U.S. Environmental Protection Agency's Air Quality System[2], the CoAgMet website[3], the New Mexico Environment Department website[4], the NWS website[5], the RAWS website[6] and from direct contact. For wind roses, hourly data (or more frequent) are needed. Ten-meter tall towers are a general standard that is used, though not all networks are set up this way. Maps of the meteorological sites that were used in this analysis are presented below, both for the whole Four Corners region and for a core area. These sites are a limited subset of the total number of possible sites, as can be seen in the site matrix tables in a different section of this overall report.

Wind roses were developed using hourly wind speed and wind direction data from 2006. Annual wind roses were developed as well at daytime (6:00 a.m. – 6:00 p.m.) and nighttime (6:00 p.m. – 6:00 a.m.). These wind roses were then overlaid on both political boundary maps and topographical maps (see annual/daytime/nighttime wind rose maps).

In looking at the annual wind roses, it is evident that some sites are more influenced by local topography than others. An example is the Cortez CoAgMet site, which is located in the valley between Sleeping Ute Mountain and Mesa Verde and is subjected to definite channeling effects. Another example is the U.S. Forest Service Shamrock site, which is located on the side of a hogback ridge. It can also be seen that the strongest winds are generally from a more westerly direction than an easterly one. From the daytime wind roses, there are general westerly or northerly/southerly components to the winds. In comparison, the nighttime wind roses show more of general easterly to northerly components. These trends are expected based on prevailing regional wind patterns as well as more local convection heating and cooling patterns along with topography.

These wind roses can be broken down even further, such as only for summer afternoon periods when ozone levels are expected to be highest (see summer afternoon wind rose maps). These wind roses show, in general, a predominant westerly to southwesterly component. As mentioned previously, some sites still exhibit wind patterns that are strongly influenced by local topography rather than more regional winds. However, these types of plots are useful in describing what may happen with air pollution flows during different periods of time. While not performed for this analysis, additional seasonal plots could be dome, such as for winter when inversions are more prevalent.

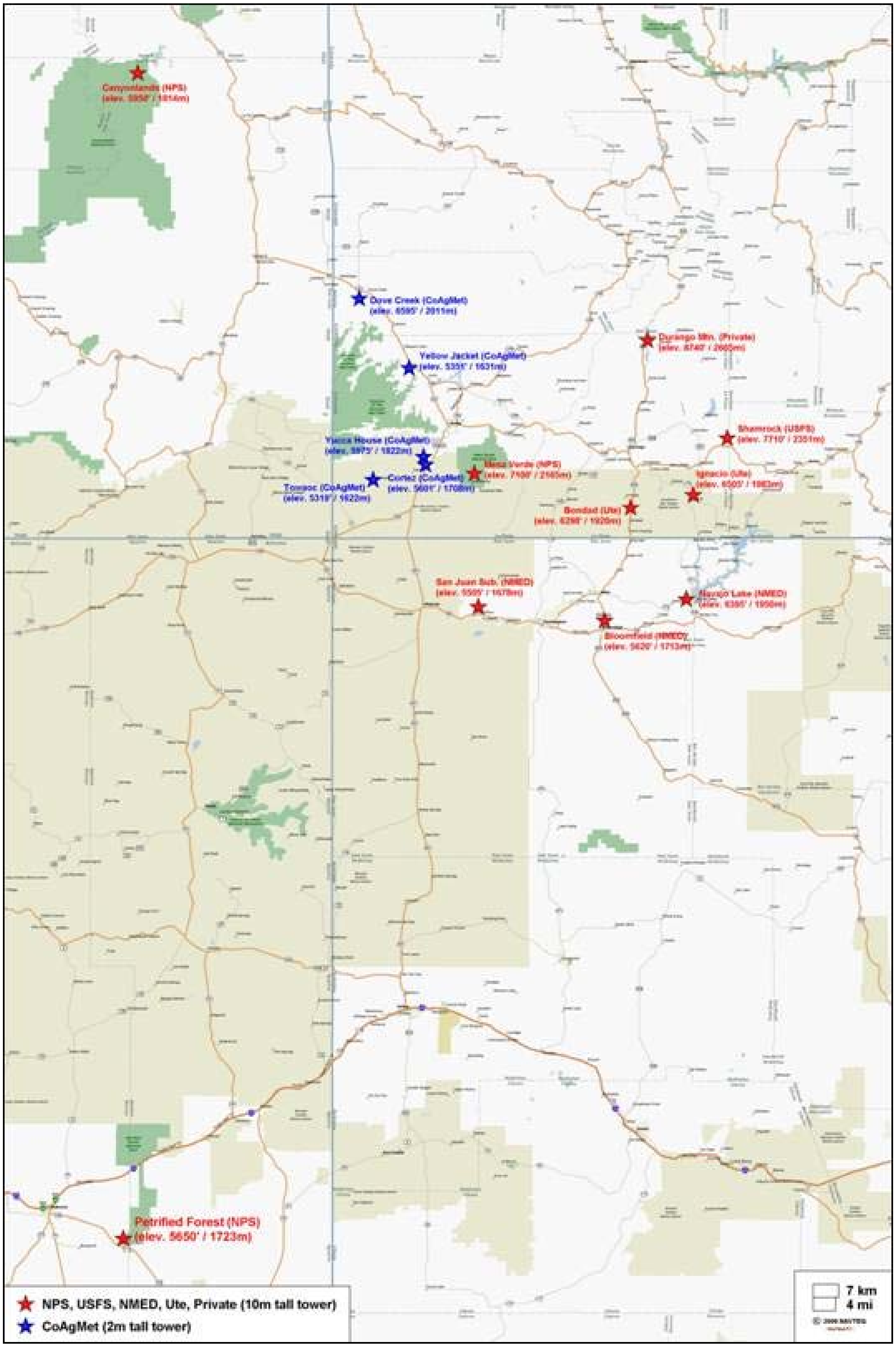
Data Gaps:
No significant data gaps exist for meteorological monitoring in the Four Corners region, with the exception of southwestern Utah and northeastern Arizona.

Suggestions for Future Monitoring Work:
No suggestions for additional monitoring of meteorological parameters are currently being proposed.

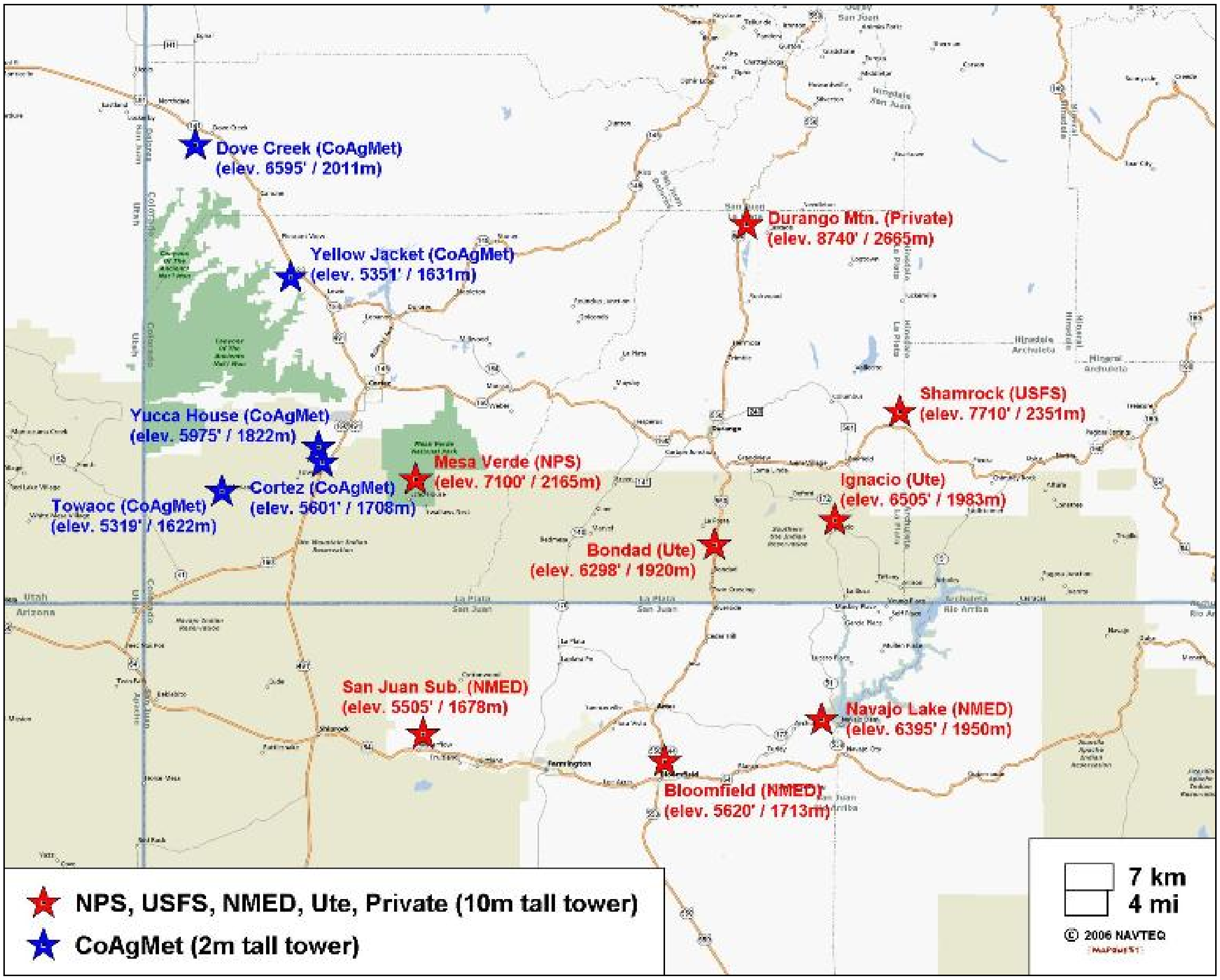
Literature Cited:

1. Lakes Environmental Software. WRPLOT View. http://www.weblakes.com/lakewrpl.html.
2. U.S. Environmental Protection Agency. http://www.epa.gov/air/data/index.html.
3. Colorado State University. Colorado Agriculture Meteorological Network. http://ccc.atmos.colostate.edu/~coagmet/.
4. New Mexico Environment Department. http://air.state.nm.us/.
5. National Weather Service. Automated Surface Observation System. http://www.nws.noaa.gov/asos/.
6. Western Regional Climate Center. Remote Automated Weather System. http://www.raws.dri.edu/index.html.

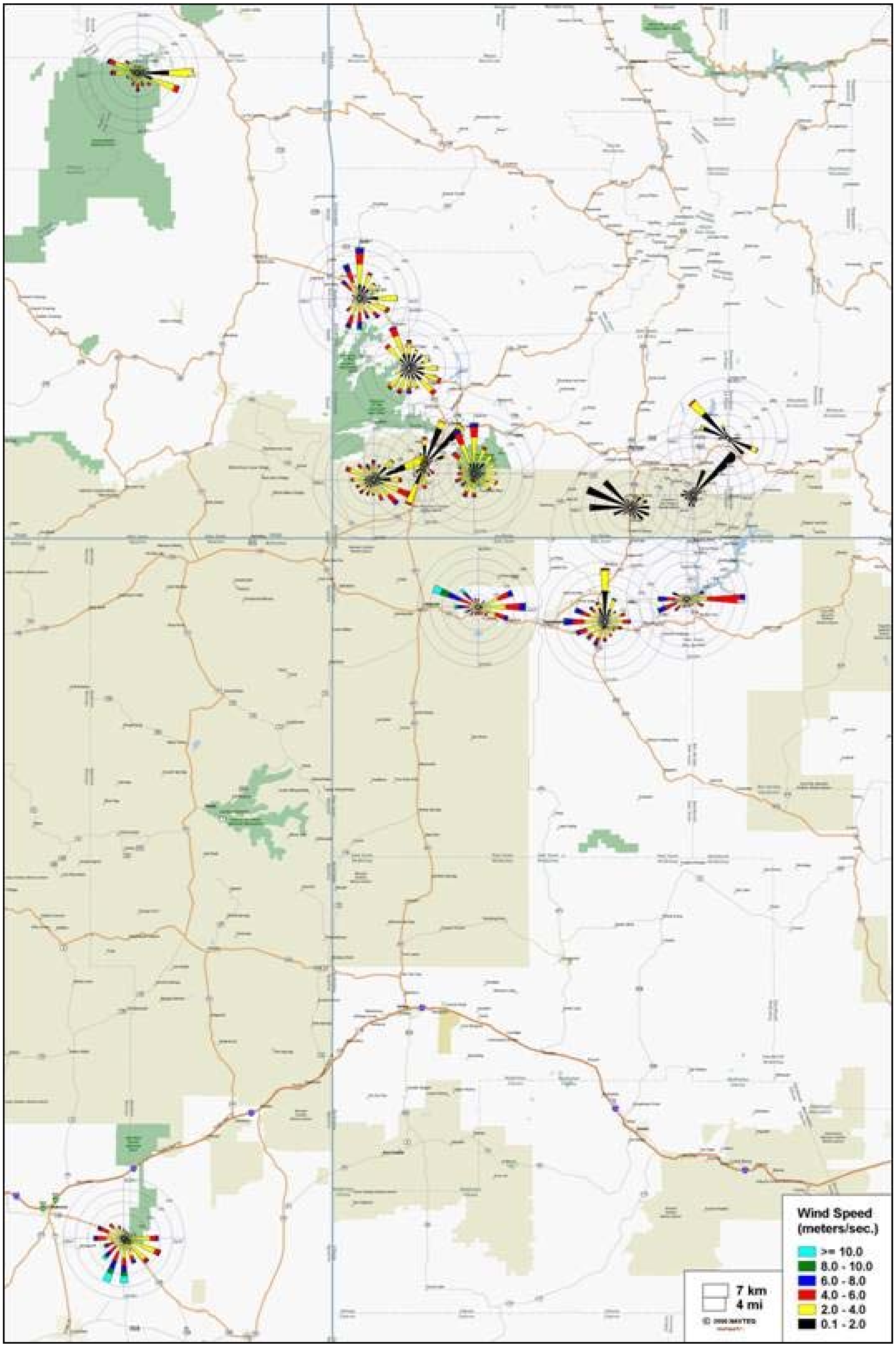
Four Corners --- Meteorological Sites in 2006



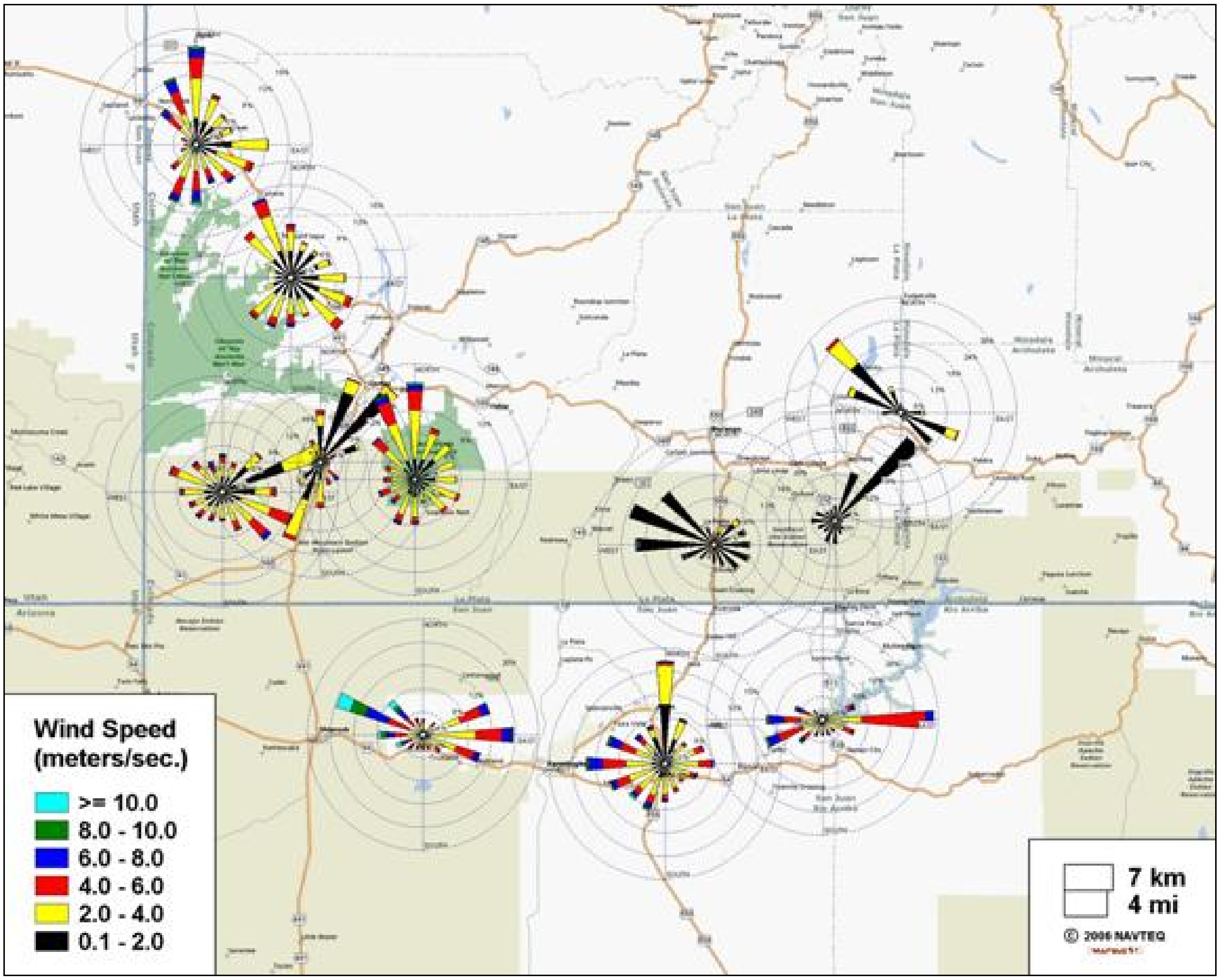
Close-in Four Corners --- Meteorological Sites in 2006



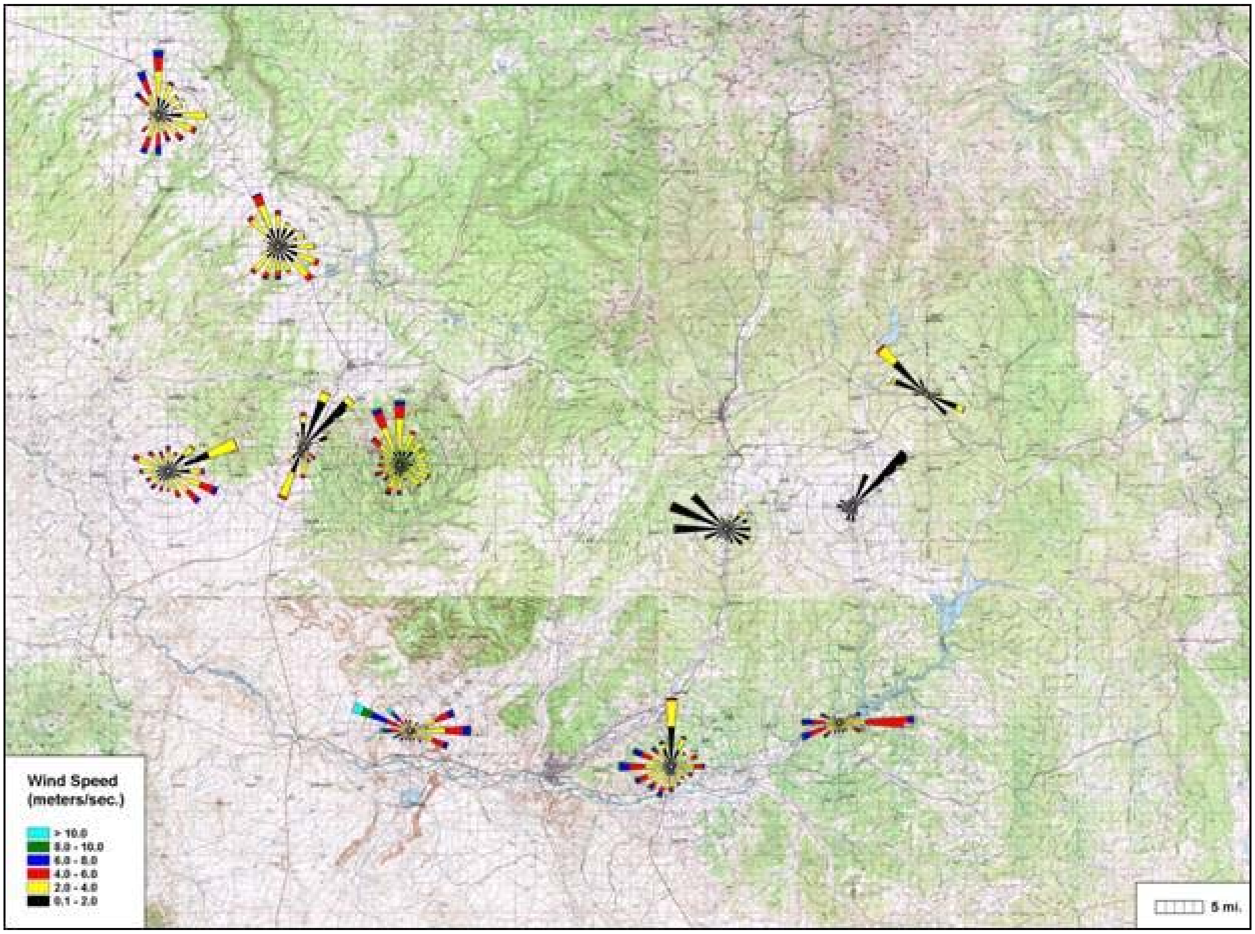
Four Corners --- 2006 Annual Wind Roses



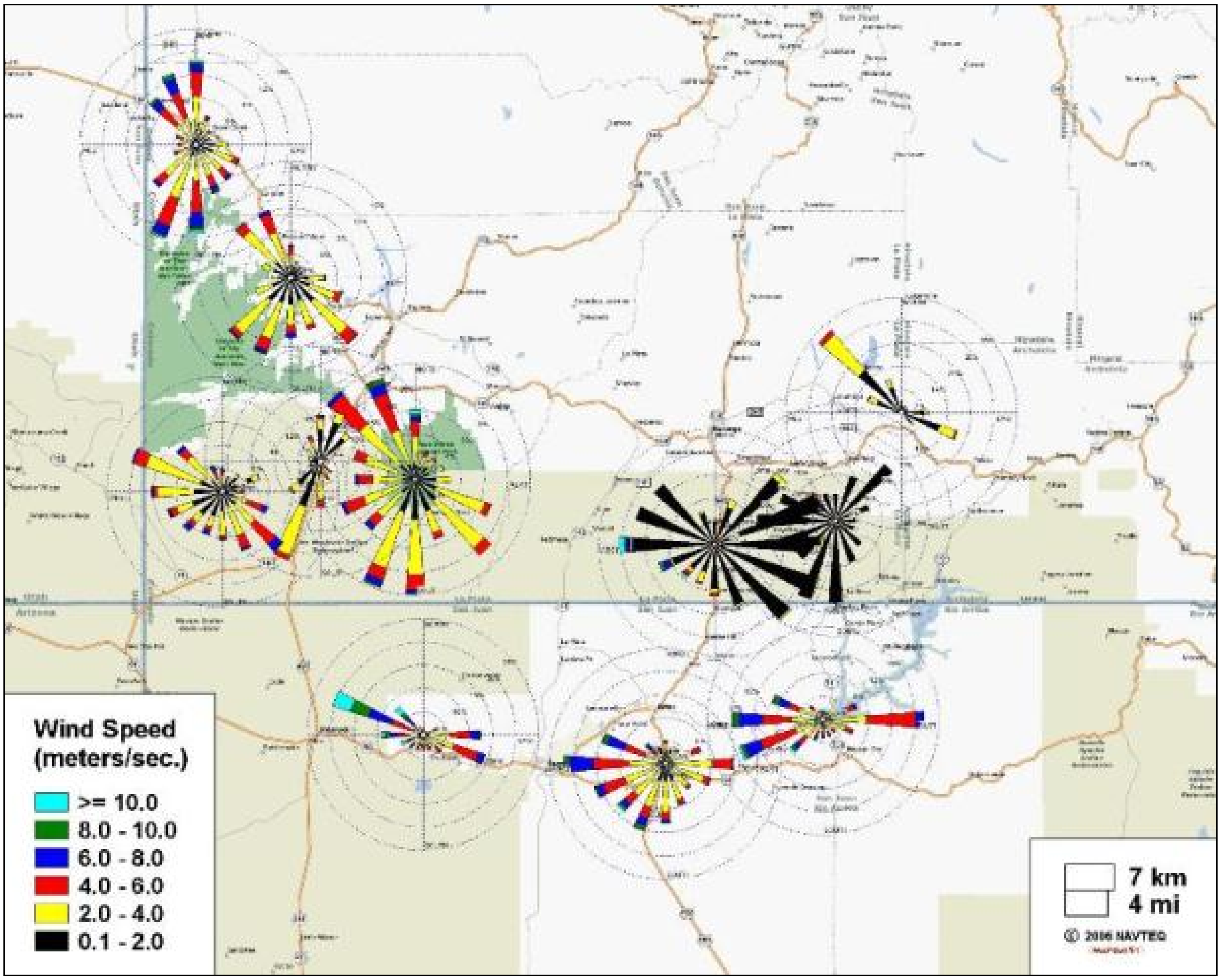
Close-in Four Corners --- 2006 Annual Wind Roses
(Political boundary map)



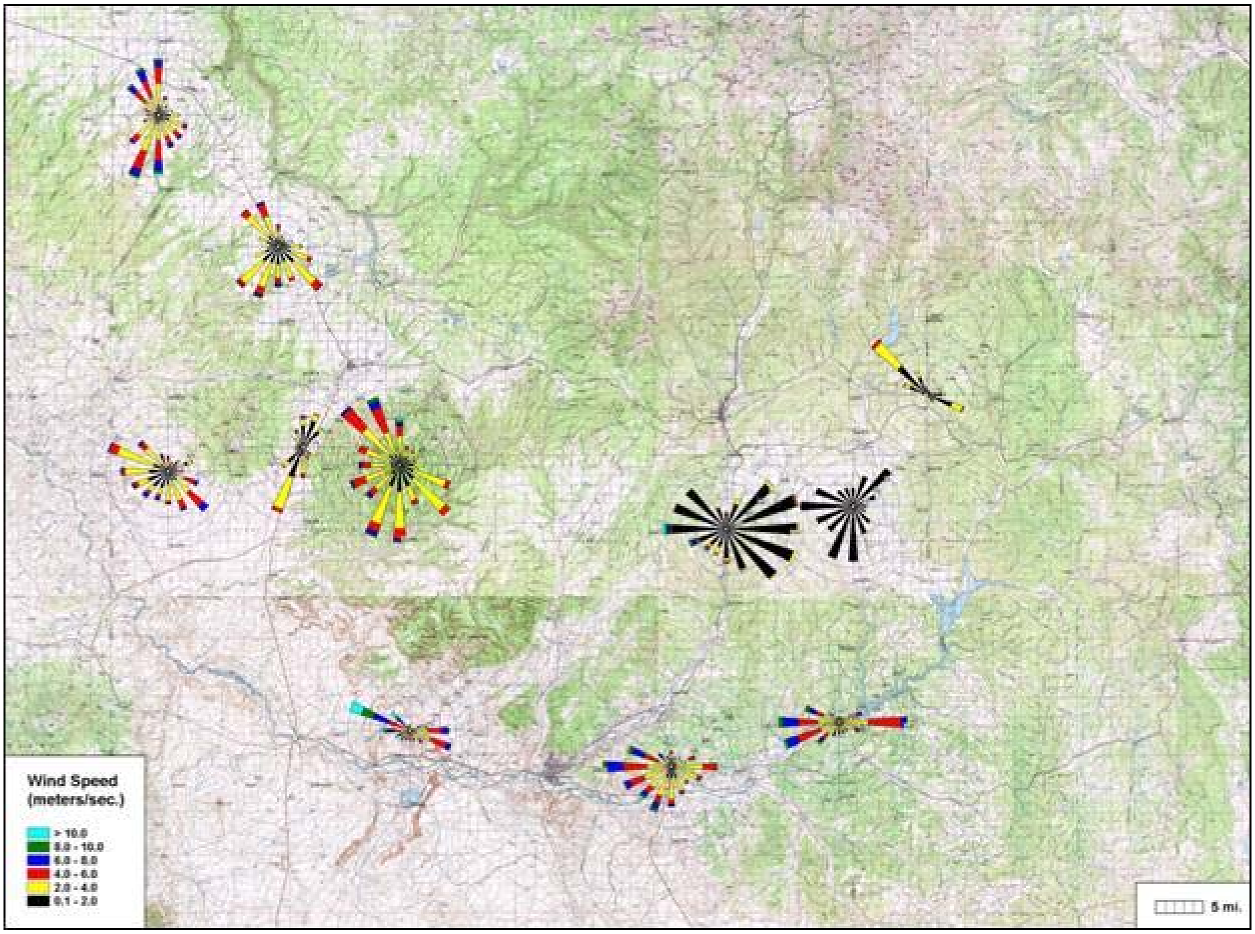
Close-in Four Corners --- 2006 Annual Wind Roses
(Topographic map)



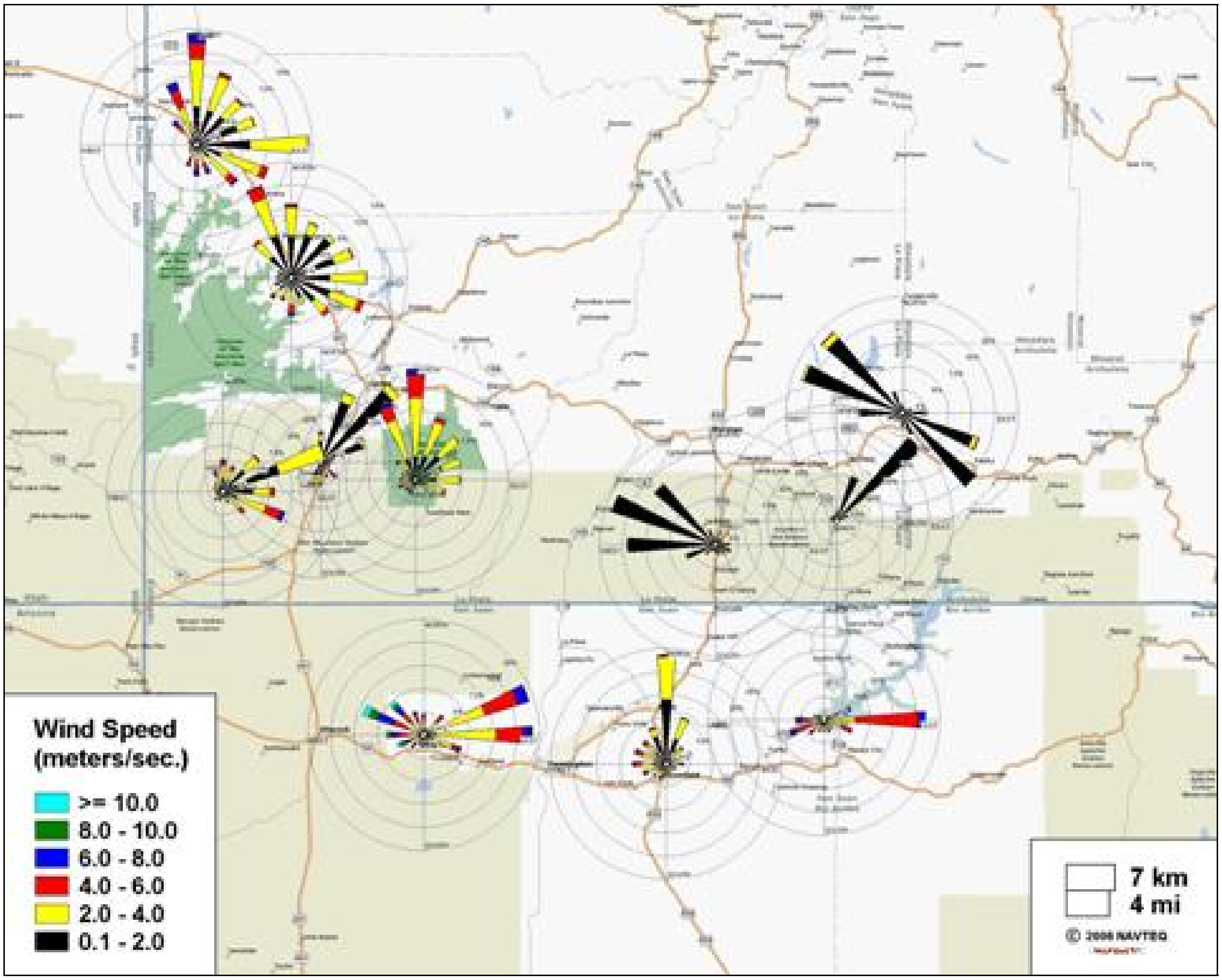
Close-in Four Corners --- 2006 Daytime Wind Roses
(Political boundary map)



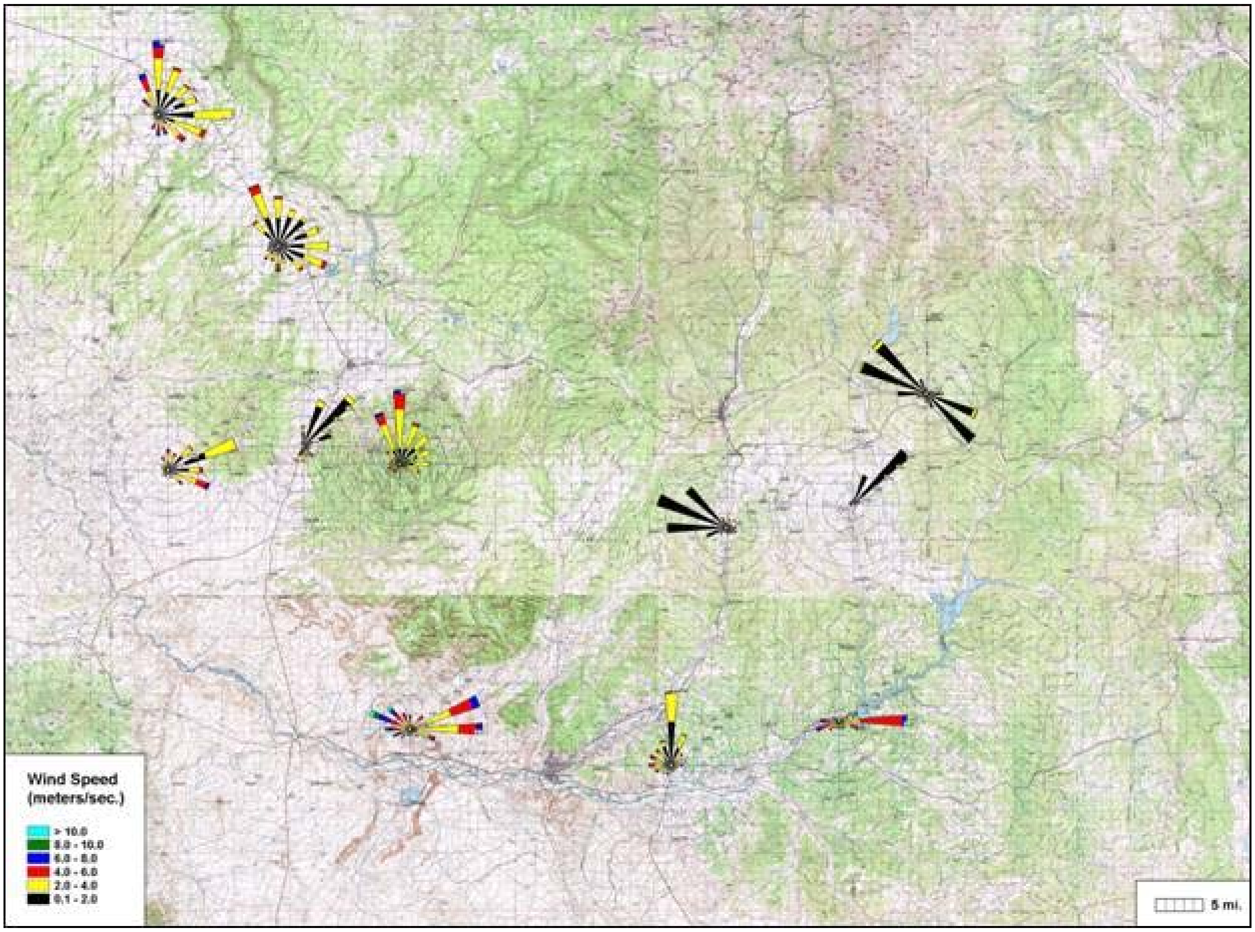
Close-in Four Corners --- 2006 Daytime Wind Roses
(Topographic map)



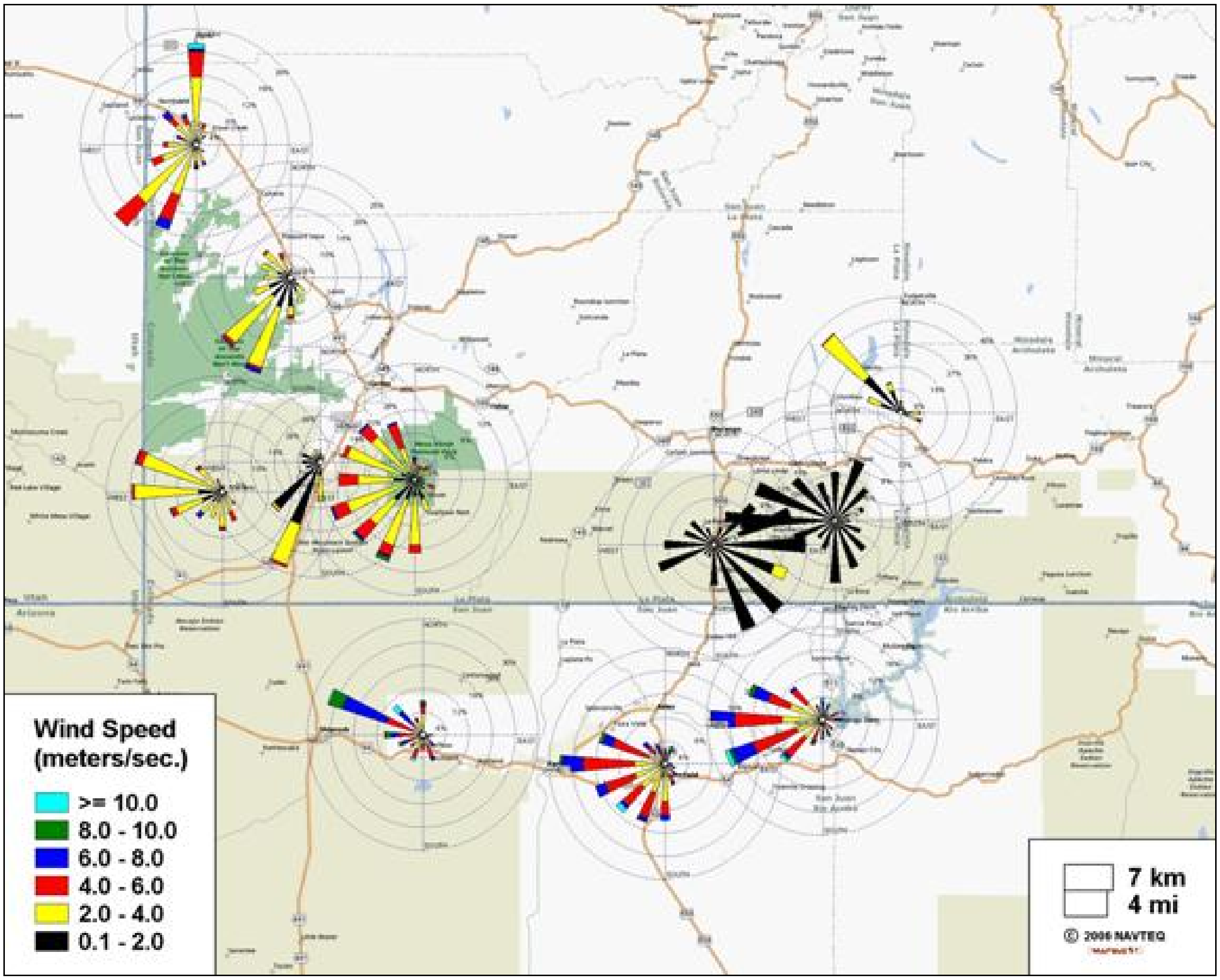
Close-in Four Corners --- 2006 Nighttime Wind Roses
(Political boundary map)



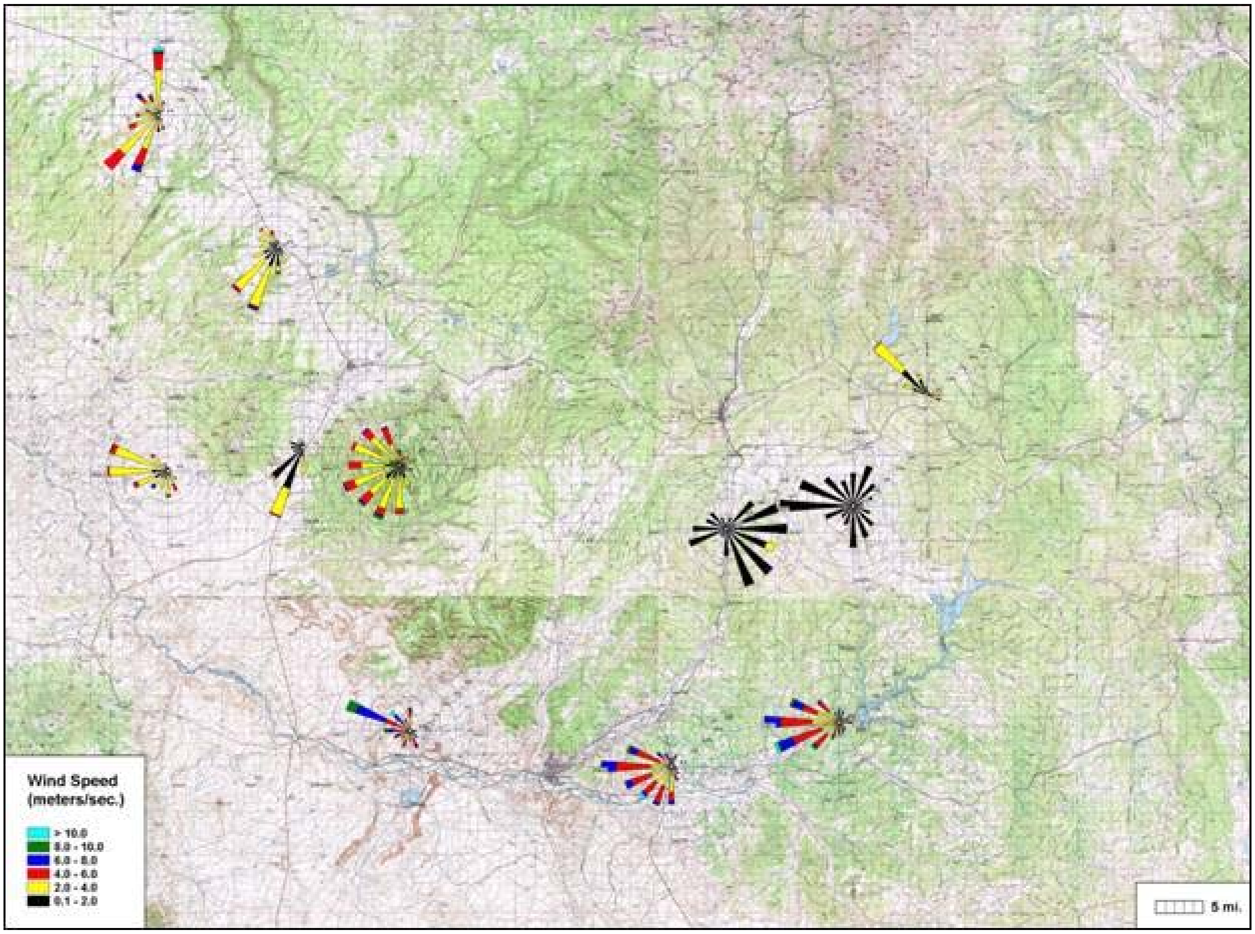
Close-in Four Corners --- 2006 Nighttime Wind Roses
(Topographic map)



Close-in Four Corners --- 2006 Summer Afternoon Wind Roses
(Political boundary map)



Close-in Four Corners --- 2006 Summer Afternoon Wind Roses
(Topographic map)



Ozone and Precursor Gases

Background:

Rationale and Benefits:

Ozone is a colorless, odorless and tasteless gaseous pollutant that is both necessary and harmful to human health. In the stratosphere where it occurs naturally, it provides a barrier to ultraviolet radiation. However, at ground-level in the troposphere, ozone is the prime ingredient of smog. When inhaled, ozone can cause acute respiratory problems, aggravate asthma, cause significant temporary decreases in lung capacity, cause inflammation of lung tissue, impair the body's immune system defenses and lead to hospital admissions and emergency room visits.[1] In addition, ground-level ozone ruptures the cells of green leaves, thereby interfering with the ability of plants to produce and store food, so that growth, reproduction and overall plant health are compromised.

Generally, ozone is a secondary-formation pollutant in the troposphere. That is, ozone is not emitted directly into the air, but is formed from precursor gases called oxides of nitrogen (NOx) and volatile organic compounds (VOCs) that in the presence of heat and sunlight react to form ozone.[1] Thus, ozone is generally an afternoon, summertime issue. Due to the process in which it is formed, however, high ozone levels typically do not occur in the area where the precursor gases are emitted, but may be a few to hundreds of miles away (depending on the meteorology). This means that ozone can be both a regional and a local concern.

VOCs and NOx, the ozone precursor gases, are emitted from both man-made sources (i.e. combustion, oil and gas development, etc.) and natural sources (i.e. plants, forest fires, etc.). VOC's that specifically can lead to ozone formation are generally called non-methane organic compounds (NMOCs) and do not include chlorinated compounds. In general, alkenes, aromatic hydrocarbons and carbonyls have a high ozone formation potential (higher incremental reactivity) while alkanes have a lower potential.[2] NOx primarily consists of nitric oxide (NO) and nitrogen dioxide (NO_2). NO_2, like ozone, is designated as a "criteria" pollutant that has a health-based National Ambient Air Quality Standard (NAAQS).

The NAAQS for ozone is set at a level of 0.08 parts per million for the three-year average of the annual fourth-maximum 8-hour values. However, the Clean Air Scientific Advisory Committee (CASAC) is currently recommending that the standard be reduced to a level in the range of 0.060 to 0.070 parts per million.[3] The NAAQS for NO_2 is set at 0.053 parts per million for an annual average.

Existing ozone data for the Four Corners region:

Ground level ozone is currently monitored on a continuous basis at nine locations in the Four Corners region, with seven sites being in a core area (see ozone sites maps). Two other sites in the region previously monitored for ozone. For regulatory comparisons to the NAAQS, continuous analyzers that have been designated as "equivalent' or "reference" by the U.S. Environmental Protection Agency (EPA) are used. In Colorado, current monitoring is performed at Mesa Verde National Park, two Southern Ute Tribe sites and at the U.S. Forest Service (USFS) Shamrock site near Bayfield. In New Mexico, monitoring is performed at three New Mexico Environment Department (NMED) sites near the San Juan power plant, Bloomfield and Navajo Lake. A Navajo Nation site in Shiprock, NM is planned to commence operation by the end of 2007. The closest site in Arizona is located at Petrified Forest National Park and the closest site in Utah is at Canyonlands National Park. With the exception of the USFS Shamrock site, all of the data are available on EPA's Air Quality System.[4]

Currently, ambient ozone levels in the Four Corners region are below the level of the current NAAQS (see trends and standards graphs). However, at Mesa Verde and one Southern Ute site there is an increasing trend, and the two newer sites (USFS, Navajo Lake) are recording higher levels. Many of the sites would be above the level of a reduced NAAQS, as proposed by CASAC.

In addition, in 2003, EPA conducted a passive ozone monitoring study in the area as part of a Region 6 ozone gap study. Seven passive ozone monitoring sites were established in San Juan County in New Mexico.[5] The data showed significantly high ozone concentrations in the western and northeastern areas of San Juan County, New Mexico, in addition to the high ozone concentrations already found in the north central area of the County.[6]

Pollutant roses were developed to help provide ideas on where ozone precursor sources may come from and where high ozone concentrations may be found. Pollutant roses, like wind roses, are a simple visual way to depict pollutant concentrations as a function of wind direction for a period of time. Pollutant roses are based on the direction that the wind is blowing from. Another way of visualizing a pollutant rose is to picture yourself standing in the center of the plot and facing into the wind. The wind direction is broken down in the 16 cardinal directions (i.e. N, NNE, NE, ENE, E, ESE, SE, SSE, S, etc). The pollutant concentration is broken down into multiple ranges. The length of each arm of the pollutant rose represents the percentage of time the wind was blowing from that direction. The longer the arm, the greater percentage of time the wind is blowing from that direction. Since the occurrence of pollutant concentrations of different ranges from a particular direction are stacked on the radius in order of increasing speeds, one must compare the length of each color to the distance between the percent circles to get the percent of time each range of pollutant concentration occurred. The circles representing the percent of time can vary from rose to rose hence each rose must be checked for the values. Pollutant roses can be generated by a number of commercially available software programs. For this analysis, WRPLOT View from Lakes Environmental Software was employed.[8]

With ozone typically having peak concentrations in the summer afternoons when sunlight is strongest, pollutant roses were developed accordingly and were placed on both political boundary and topographic base maps (see pollutant rose maps). As can be seen from these pollutant rose maps, ozone at the three southern core area sites in New Mexico and the Mesa Verde site in Colorado show predominantly westerly wind directions in this summer afternoon timeframe. This generally mirrors the predominant San Juan River drainage. The two Southern Ute Tribe sites and the Forest Service Shamrock site appear to be heavily influenced by local topography. Thus, based on these pollutant roses, it is likely that ozone concentrations could also be high further to the east and north of the New Mexico Navajo Lake site, further up the San Juan River and Piedra River drainages. While no monitoring exists to confirm or deny, winds could also flow up other drainages in summer afternoons, including the Dolores and Animas Rivers.

For ozone precursor gases, NOx monitoring currently exists at six sites in the Four Corners region (see NO_2 sites map), including two Southern Ute tribe sites and the USFS Shamrock site in Colorado, and three NMED sites. A Navajo Nation site in Shiprock, NM is scheduled to commence operation. Two other sites previously had NOx monitoring. NO_2 levels have been fairly steady over the years at most sites, at a level well below the NAAQS (see NO_2 trends graphs). At two sites in particular, San Juan Substation, NM and Bloomfield, NM, the NO_2 levels do appear to be increasing over time. NO, unfortunately, has not been reported consistently as it is not designated a criteria pollutant. However, NO levels do appear to be increasing at both Southern Ute Tribe sites, Ignacio and Bondad (see NO trends graphs). These increases in NO and NO_2 are of concern due to the potential for increased ozone formation and also indicates that there are increased combustion sources in the area, possibly due to oil and gas development and increased traffic. VOC baseline monitoring for San Juan County, New Mexico was conducted in 2004 and 2005 at three sites. One site was near Bloomfield, NM near some industrial sources, a second near the San Juan power plant and the third site was near Navajo Lake, in an oil and gas development area. Results showed that alkane concentrations dominated, especially ethane and propane. The biogenic compound isoprene and the highly reactive VOC compounds, ethylene and propylene, were not present in significant quantities.[6,7]

Data Gaps:

While it would appear that there is a sufficient ozone monitoring network in the Four Corners region, some areas are lacking. Pollutant roses were developed to determine the directions from which ozone precursors are most likely to be transported by wind (see ozone pollutant roses). In general, for summer afternoon periods when ozone levels are expected to be highest, winds are generally from the west to southwest. Oil and gas development increased significantly after many of the current sites were installed. This development has provided a significant increase in both VOC and NOx precursor gas sources to the region. Ozone monitoring currently exists in the major oil and gas development areas, but little downwind ozone monitoring currently exists.

VOCs are also a gap, as the short-term studies in 2004 and 2005 were located toward the southern edge of the oil and gas development area, or not in the development area at all. While emissions inventories can provide an estimate of total VOCs that may be released to the atmosphere, these are primarily based on predicted emissions, not on actual measurements. This is a concern as different VOCs have different ozone formation potentials and the oil and gas development has dramatically increased in the region since these studies.

Suggestions for Future Monitoring Work:

C. Install and operate two or three long-term continuous monitoring stations for ozone. One station would be located upstream of Navajo Lake, in the San Juan River drainage toward Pagosa Springs, CO, or in the Piedra River drainage, toward Chimney Rock, CO. This area is toward the northeastern portion of the Four Corners region and is downwind of many VOC precursor gas sources from oil and gas development. The second station would be located to the north of Cortez. This area is in the north-central portion of the Four Corners region and is downwind of both an urban area and any precursor gas emissions that would funnel up between Sleeping Ute Mountain and Mesa Verde. If funding exists, a third site in Arizona on Navajo Nation land, in the southwest portion of the Four Corners area, is recommended. This site, possibly at Canyon de Chelly National Monument, would be to the west of a high ozone area as determined in the 2003 passive ozone study and would provide a good representation of regional ozone levels entering the Four Corners area. Each site, including shelter and instrumentation, would cost approximately \$15,000 to \$20,000 (total = \$45,000 to \$60,000). Annual operating costs (not including field personnel) would be approximately \$1,500 per site (total = \$3,000).

D. Perform an ozone saturation study using passive samplers across the entire Four Corners region to determine areas of highest ozone concentration. This would help determine if existing or new continuous monitoring sites are located in appropriate areas or if continuous ozone monitors need to be added or moved. It is expected that at least 20 passive ozone sites over the four-state region would be needed. Running for 30 days during a summer, the approximate cost would be \$22,000 (not including field personnel time).

   (Note: In early July 2007, the Colorado legislature appropriated funding for passive ozone monitoring in Colorado. As a result, a short-term study was performed in three areas of Colorado at 50 locations. These areas included the north Front Range, central western and southwestern/Four Corners. For the southwestern area, 12 passive ozone sampling sites were operated from early August to early September 2007. While not a definitive study, funding is expected to be available in future years to perform more refined passive ozone monitoring.)

E. Perform monitoring for VOCs (in particular NMOCs) and carbonyls in the oil and gas development areas to determine the actual constituents in the emissions from wellheads, leaks and tanks. This would help in determining the potential for ozone formation from these compounds. This suggestion also includes follow-up monitoring for VOCs, both in and near the oil and gas development area, to compare to the 2004 and 2005 baseline data from San Juan County, New Mexico. A minimum of four to five sites is recommended; two sites in the oil and gas development area, one background site and one or two follow-up sites. For a year of monitoring, every sixth day, the approximate cost (not including field personnel time) would be \$45,000 per site (total = \$180,000 to \$225,000).

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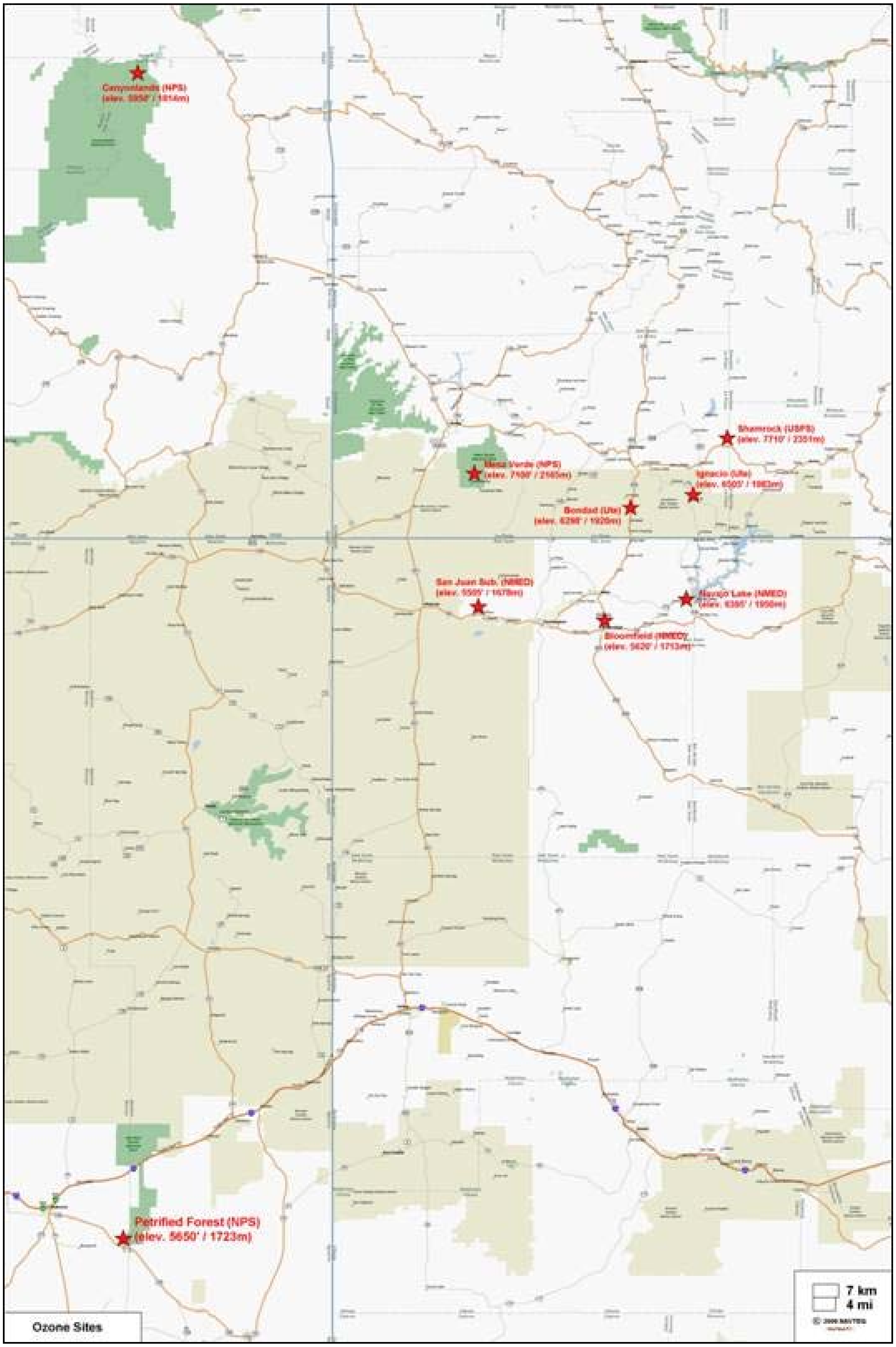
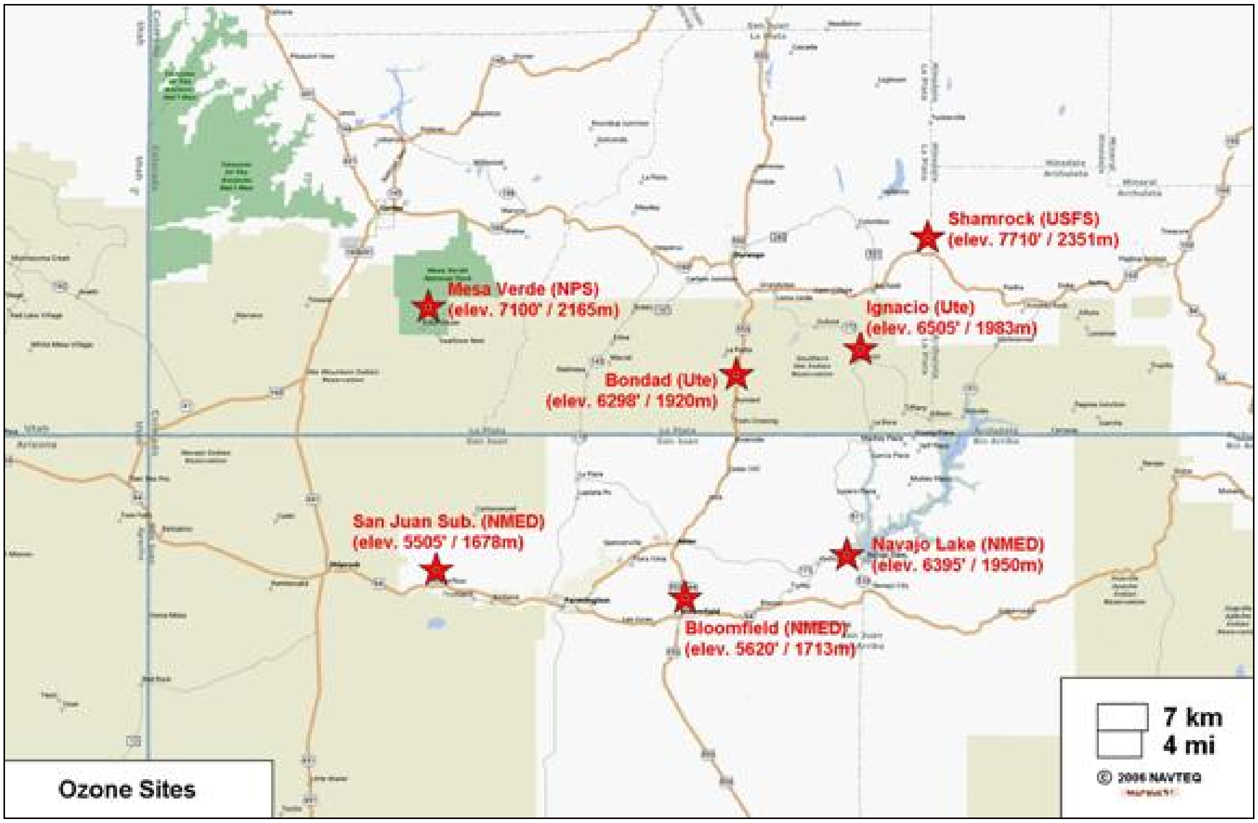
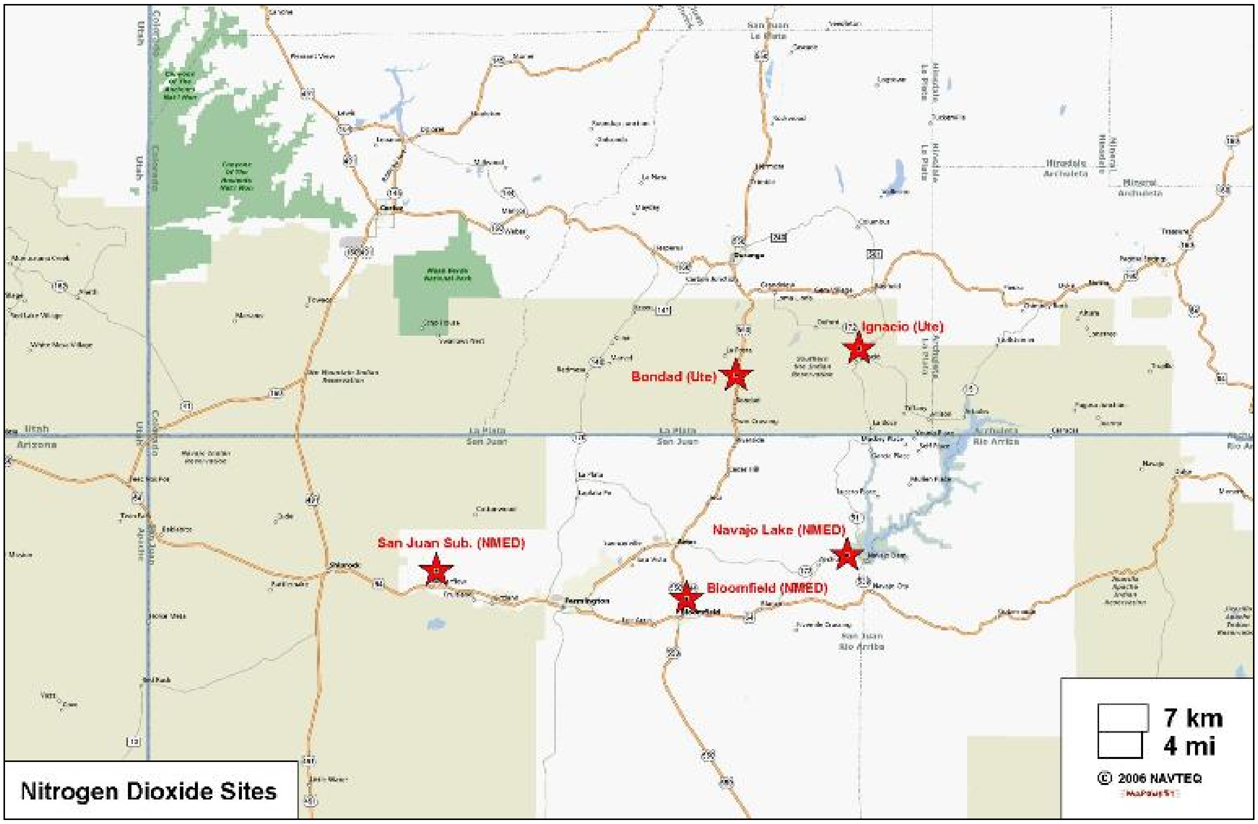
Four Corners --- Continuous Ozone Sites in 2006



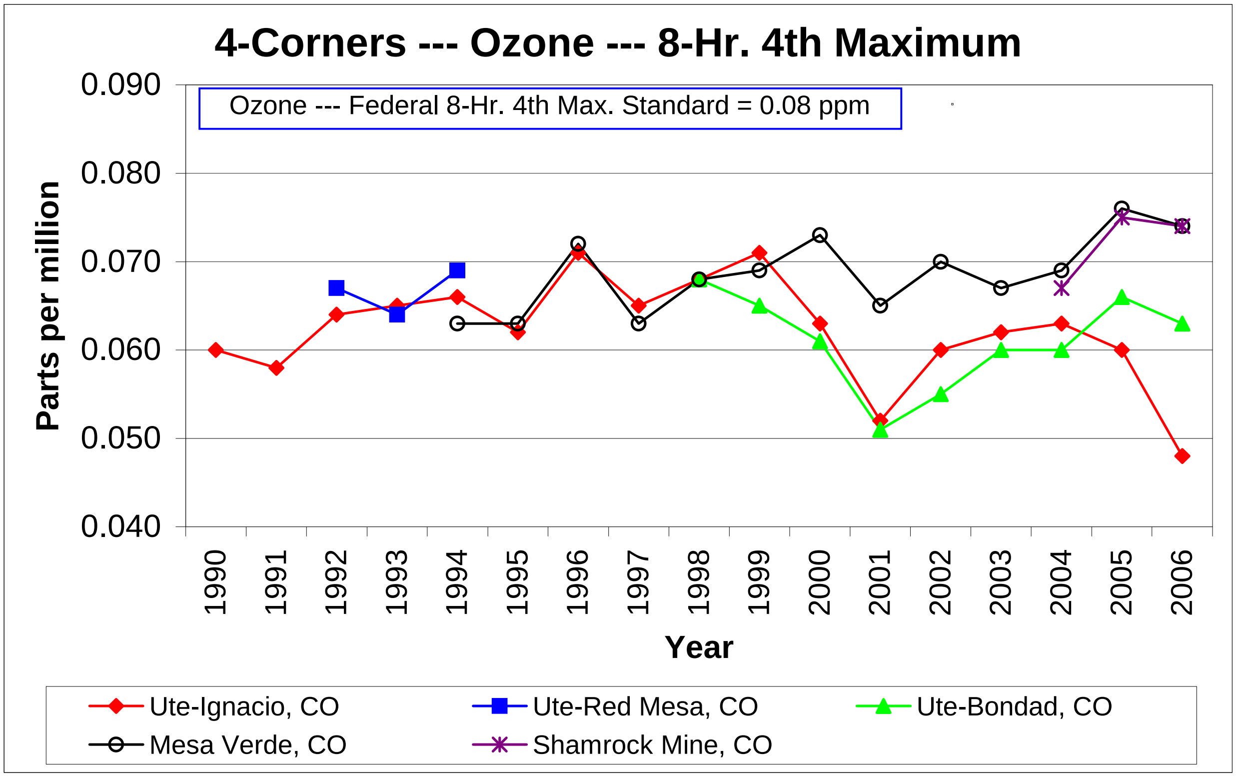
Close-in Four Corners --- Continuous Ozone Sites in 2006

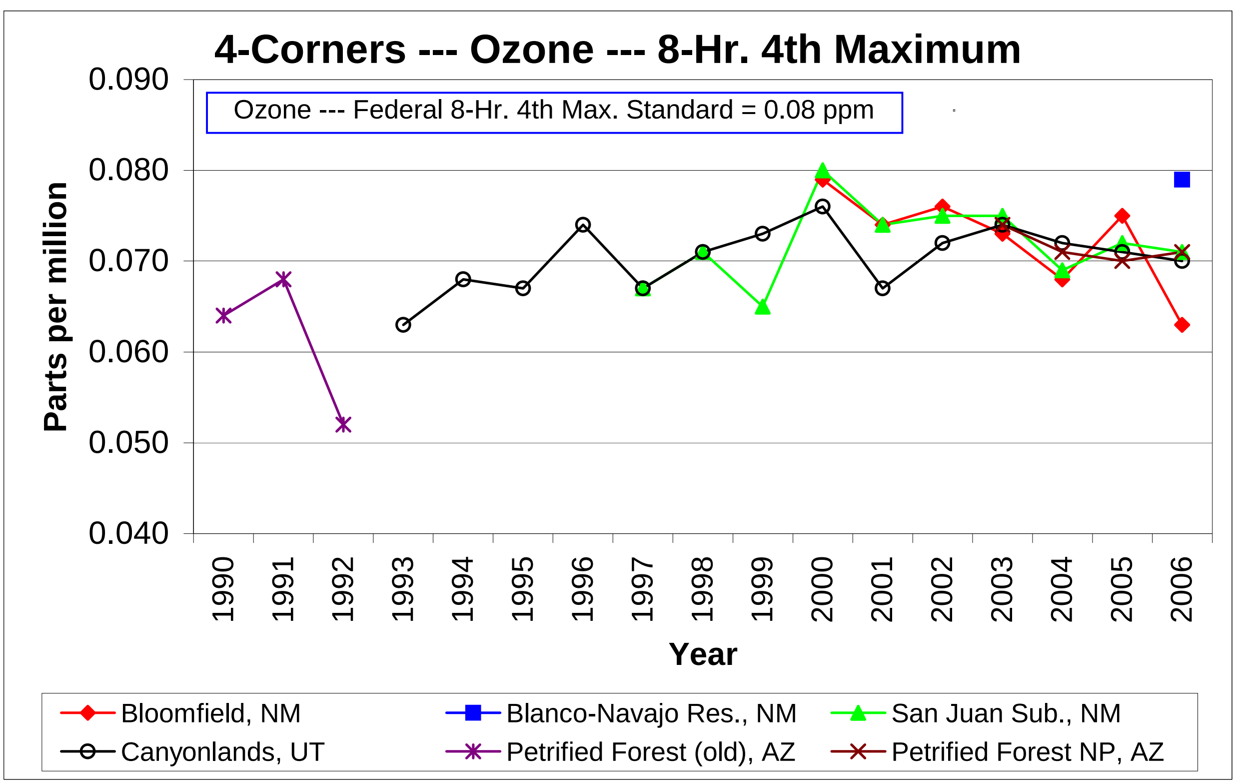


Four Corners --- Continuous Nitrogen Dioxide Sites in 2006

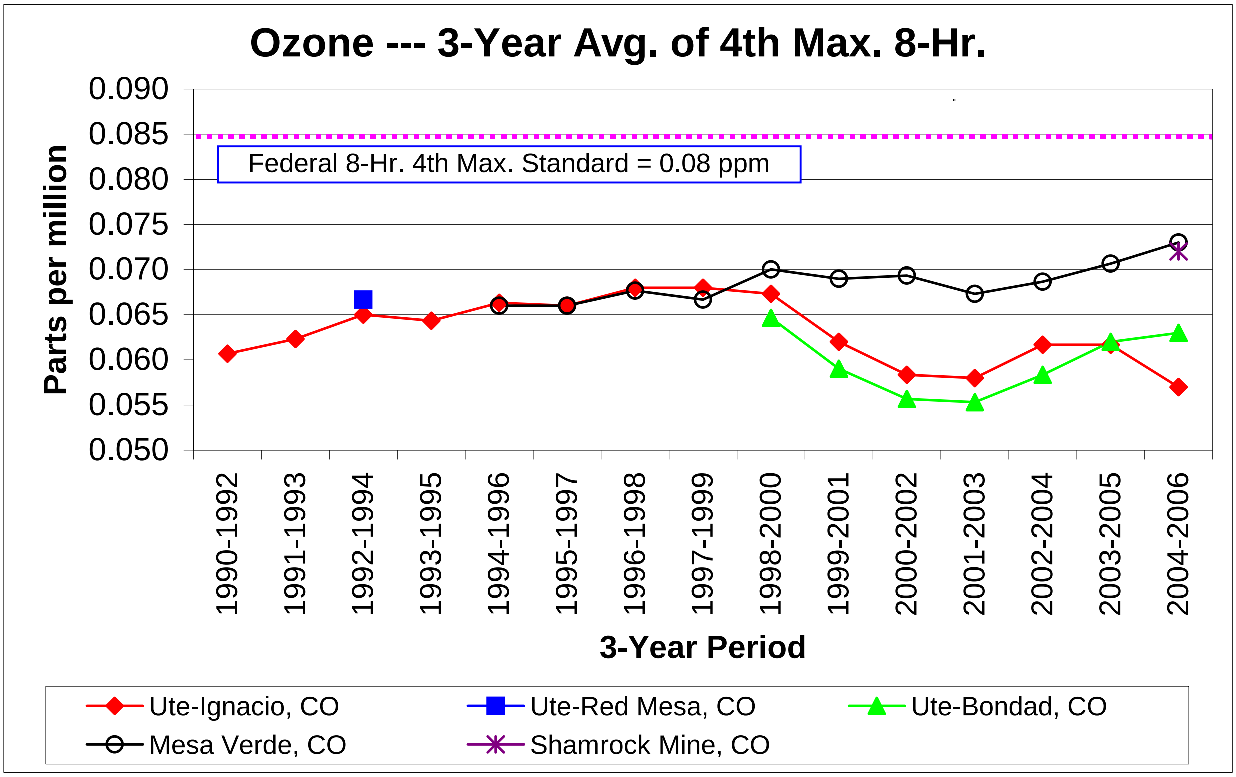


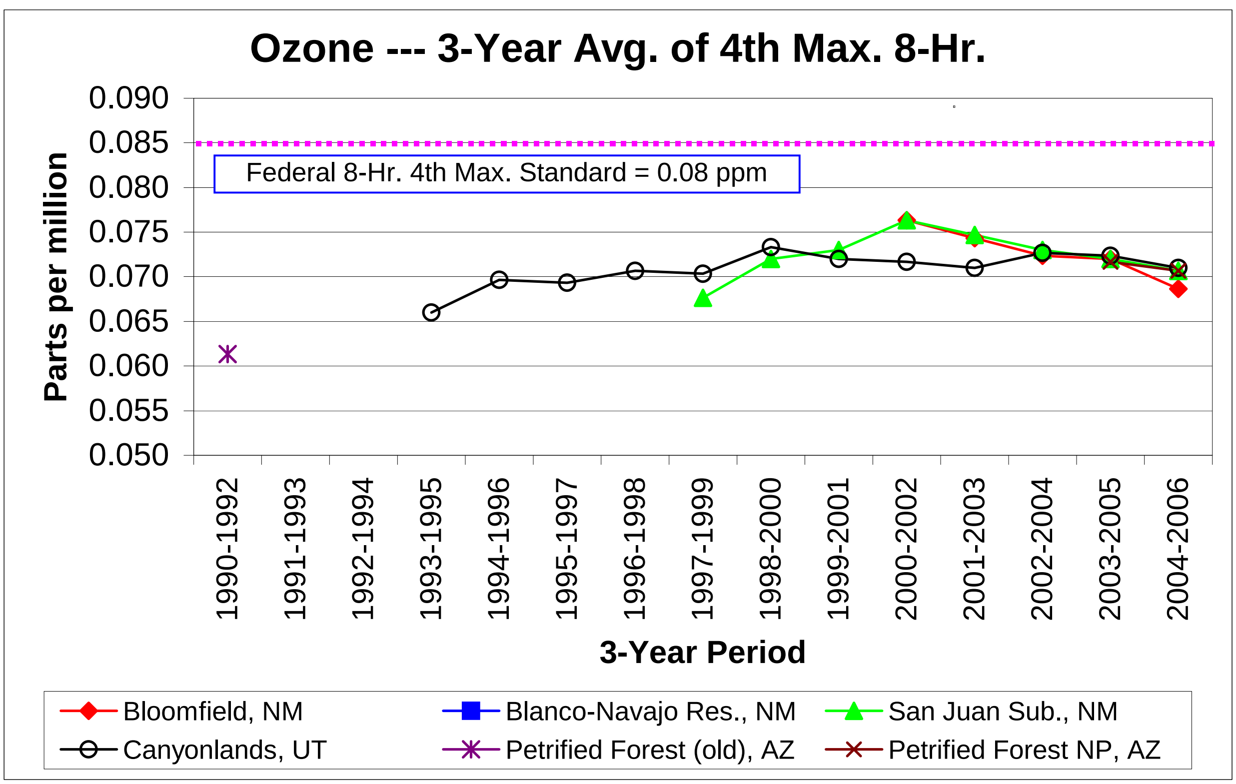
Four Corners --- Ozone Trends (4th Maximum 8-Hour)





Four Corners --- Ozone Standard (3-Year Avg. of 4th Max. 8-Hour)





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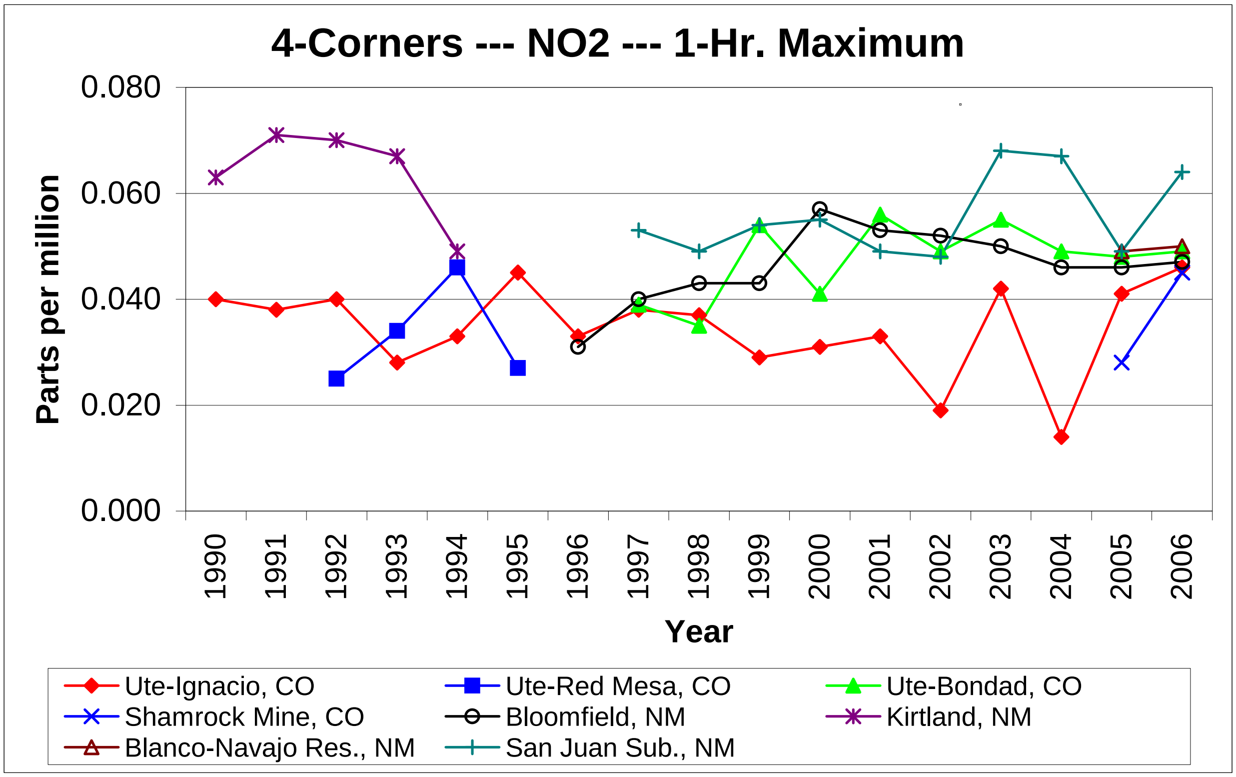
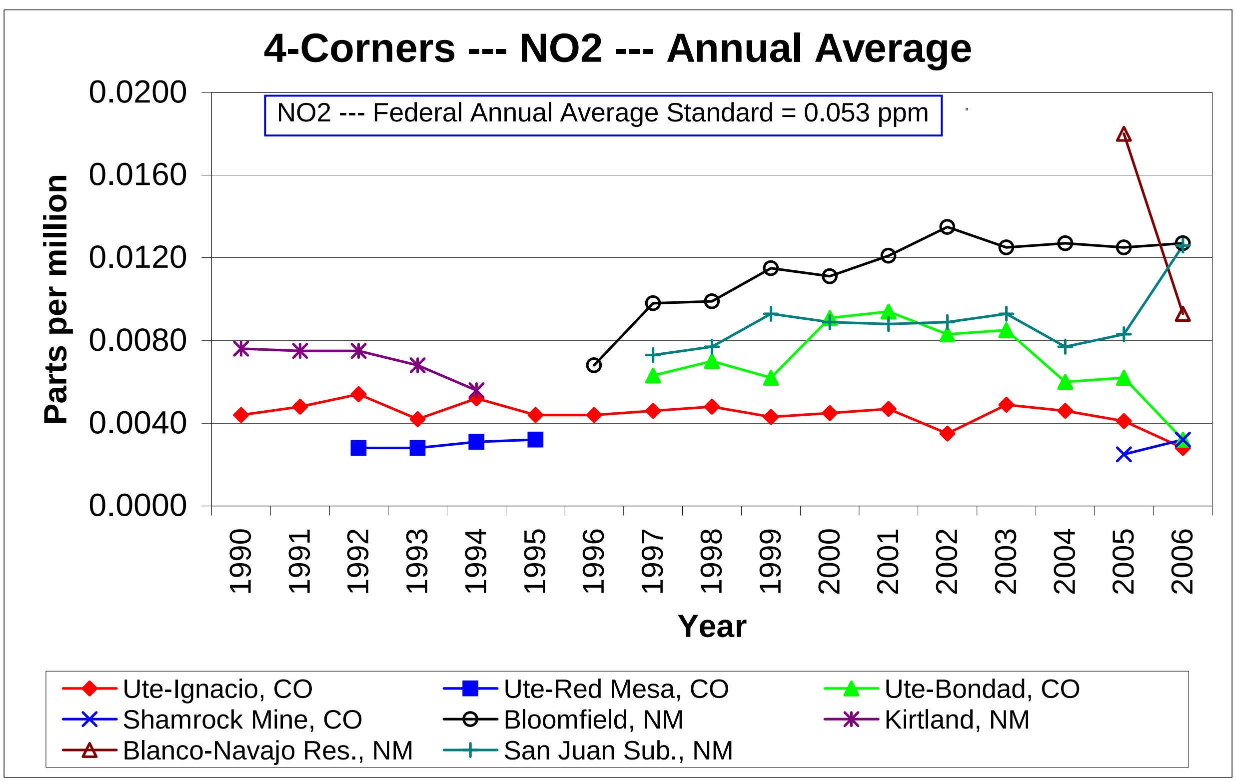
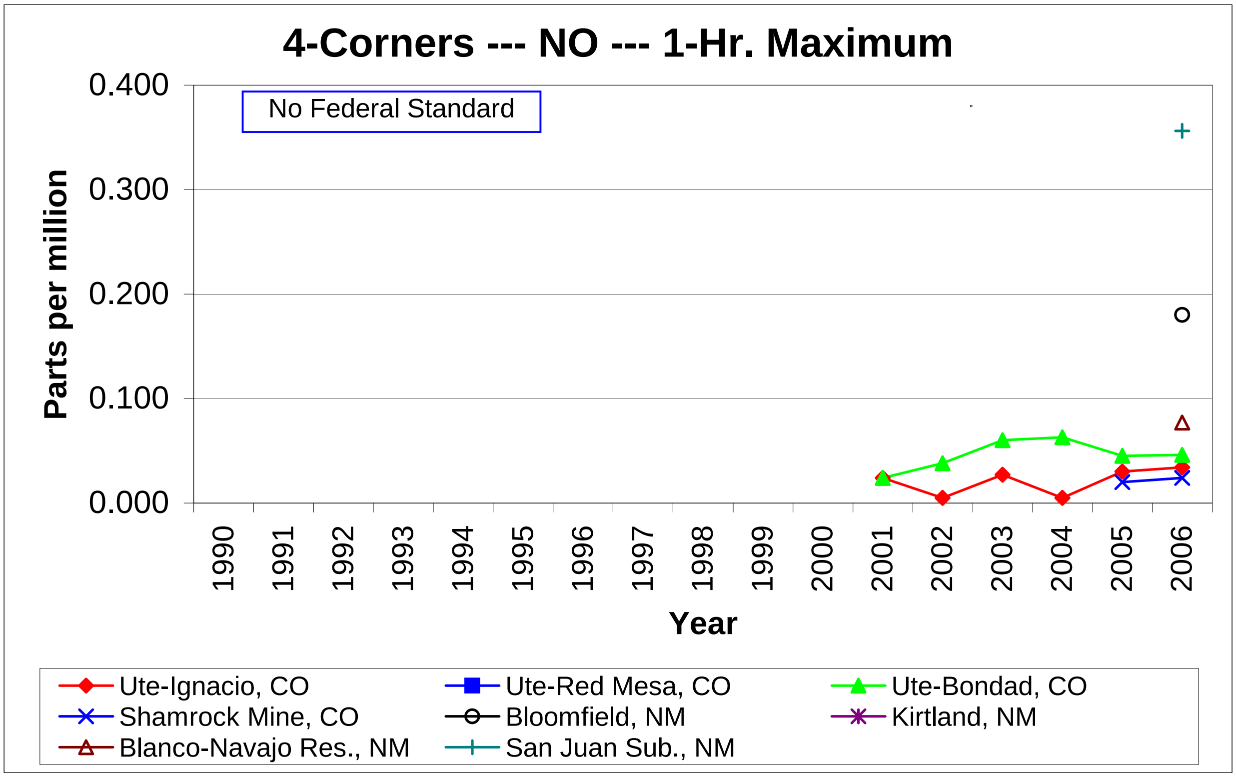
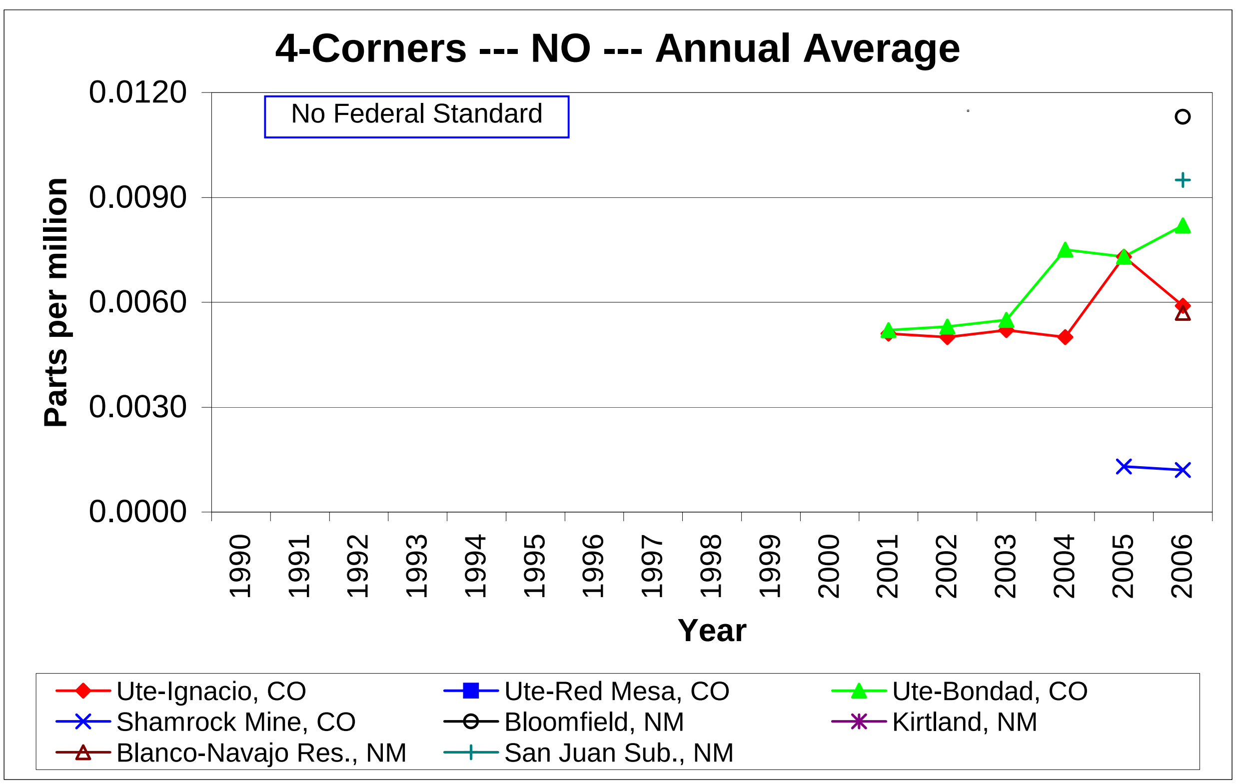


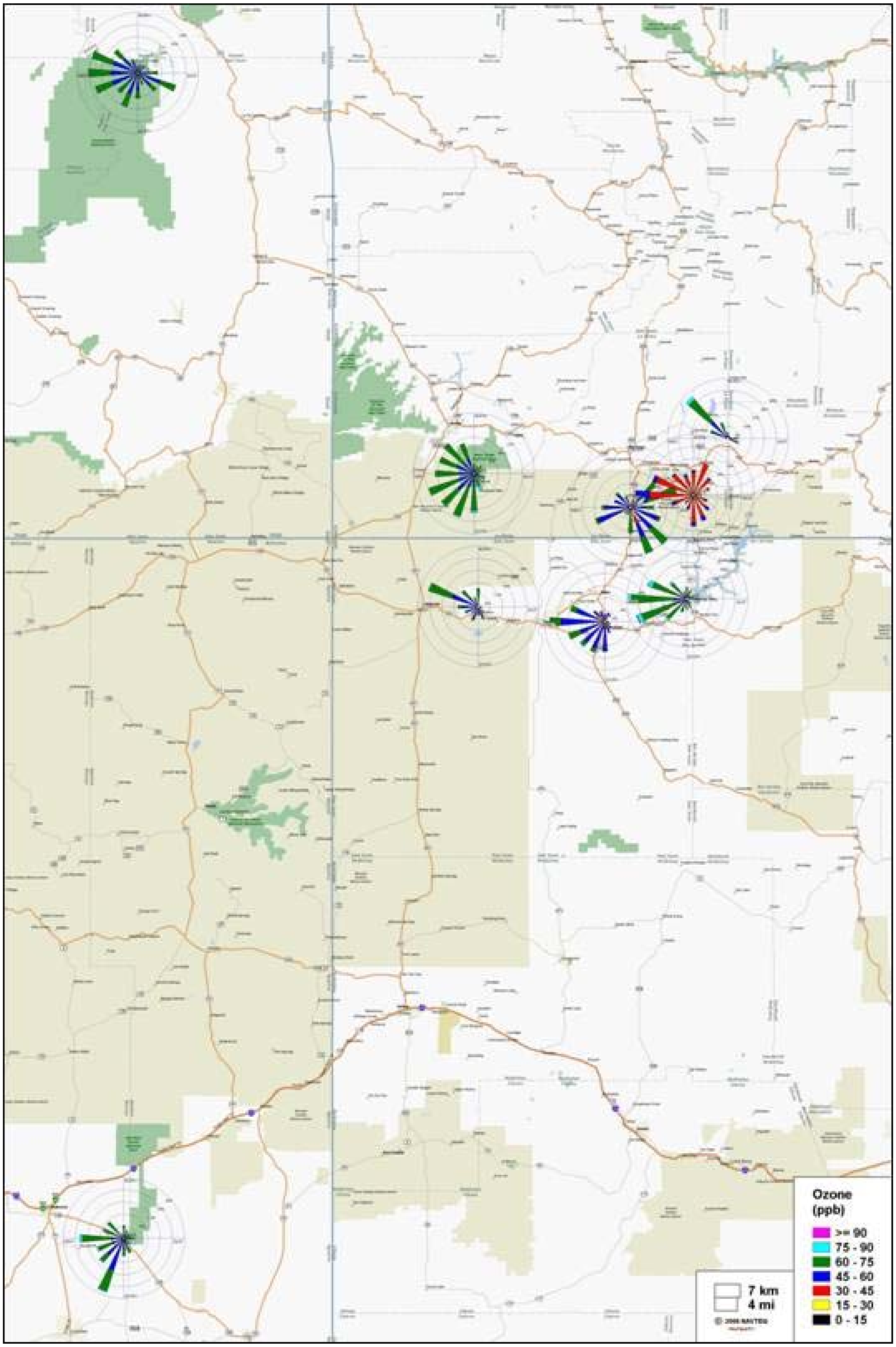


Four Corners --- Nitric Oxide Trends

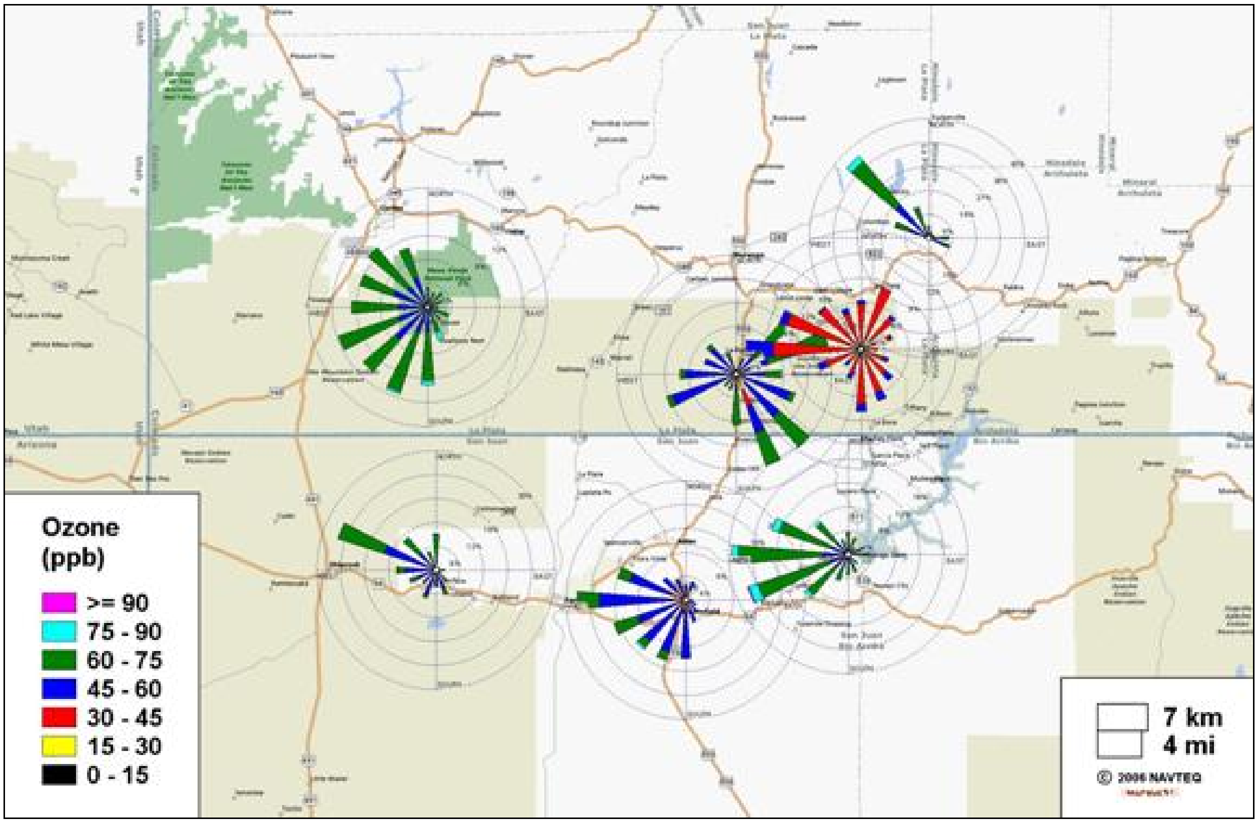




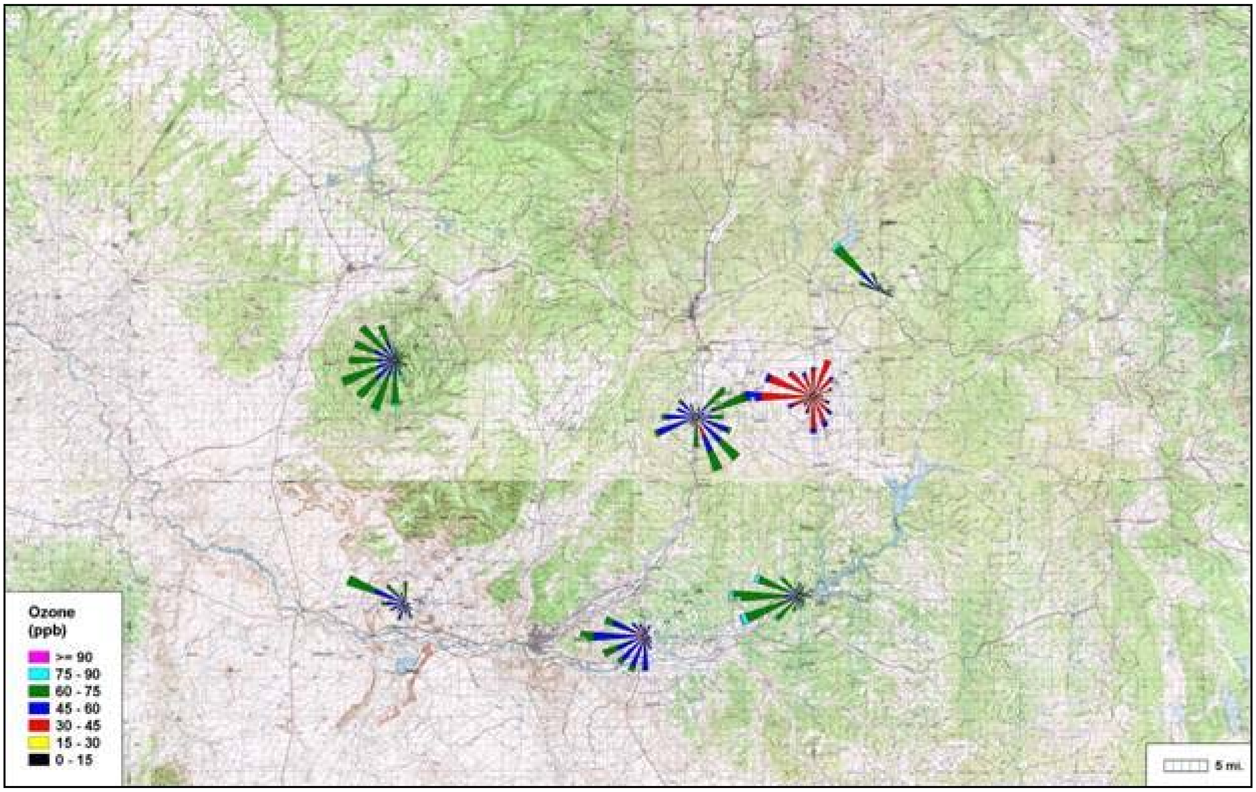
Overall Four Corners --- Summer Afternoon Ozone Pollution Roses (2006)



Close-in Four Corners --- Summer Afternoon Ozone Pollution Roses (2006) (Political boundary map)



Close-in Four Corners --- Summer Afternoon Ozone Pollution Roses (2006) (Topographic map)



Carbon Monoxide, Particulates and Other Common Pollutants

Background:

Rationale and Benefits**:**
Carbon monoxide, or CO, is a colorless, odorless gas that is formed when carbon in fuel is not burned completely. It is a component of motor vehicle exhaust, which contributes about 56 percent of all CO emissions nationwide. Other non-road engines and vehicles (such as construction equipment and boats) contribute about 22 percent of all CO emissions nationwide. Higher levels of CO generally occur in areas with heavy traffic congestion. In cities, 85 to 95 percent of all CO emissions may come from motor vehicle exhaust. Other sources of CO emissions include industrial processes (such as metals processing and chemical manufacturing), residential wood burning, and natural sources such as forest fires. Woodstoves, gas stoves, cigarette smoke, and unvented gas and kerosene space heaters are sources of CO indoors. The highest levels of CO in the outside air typically occur during the colder months of the year when inversion conditions are more frequent.[1]

Carbon monoxide can cause harmful health effects by reducing oxygen delivery to the body's organs (like the heart and brain) and tissues. This results in cardiovascular and/or central nervous system effects, such as chest pains, vision problems and reduced ability to work or exercise.[1] The health-based National Ambient Air Quality Standard (NAAQS) for carbon monoxide is set at a level of 35 parts per million for a one-hour average and 9 parts per million for an eight-hour average.[2]

Particulates are broken into two categories for NAAQS: PM_{10}, which is particulate matter that is 10-microns in diameter and smaller, and $PM_{2.5}$, which is particulate matter 2.5 microns in diameter and smaller. Thus, $PM_{2.5}$ is a subset of PM_{10}. Particulates are an inhalable mixture of solid particles and liquid droplets found in the air. Some particles, such as dust, dirt, soot, or smoke, are large or dark enough to be seen with the naked eye. Others are so small, they can only be detected using an electron microscope. These particles come in many sizes and shapes and can be made up of hundreds of different chemicals. Some particles, known as *primary particles* are emitted directly from a source, such as construction sites, unpaved roads, fields, smokestacks or fires. Others form in complicated reactions in the atmosphere of chemicals such as sulfur dioxides and nitrogen oxides that are emitted from power plants, industries and automobiles. These particles, known as *secondary particles*, make up most of the fine particle pollution in the country.[3]

Particle pollution, especially fine particles, contains microscopic solids or liquid droplets that are so small that they can get deep into the lungs and cause serious health problems. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including increased respiratory symptoms (such as irritation of the airways, coughing, or difficulty breathing), decreased lung function, aggravated asthma, development of chronic bronchitis, irregular heartbeat, nonfatal heart attacks and premature death in people with heart or lung disease.[3] The health-based NAAQS for PM10 is set at a level of 150 micrograms per cubic meter for a 24-hour average. For PM2.5, the health-based NAAQS are set at levels of 35 micrograms per cubic meter for a 24-hour average and 15 micrograms per cubic meter for an annual average.[2]

Other common pollutants in the ambient air that are not covered in other option papers may include lead, carbon dioxide, organic compounds/hazardous air pollutants (HAPs), pesticides, and others. Of these, only lead has a health-based NAAQS, which is 1.5 micrograms per cubic meter for a calendar quarter average.[2]

Lead is primarily emitted from metals processing or waste incinerator sources. Historically, leaded automobile fuels were the primary source.[4] Lead is typically associated with neurological impairment. Carbon dioxide is emitted from a variety of natural and human-related sources. With implications as a greenhouse gas rather than health concerns, the largest man-made source of carbon dioxide, by far, is fossil fuel combustion.[5] Organic compounds can be both toxic and non-toxic in nature. Toxic air pollutants, also known as hazardous air pollutants, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental effects. These compounds can come from a variety of sources, though primarily from industrial or mobile (i.e. motor vehicle) source. Thus, they are typically associated with urban areas.[6] The U.S. Environmental Protection Agency currently lists 188 HAPs for which it would like to reduce atmospheric releases/emissions. While no ambient standards currently exist for these pollutants, workplace standards do exist for some of them. Pesticides are substances or mixture of substances intended for preventing, destroying, repelling, or mitigating any pest.[7] While all regulated pesticides have been tested for health impacts to humans, exposures can and do occur from improper use.

Existing data for the Four Corners region:
Carbon monoxide in the ambient air is currently monitored on a continuous basis at only one site in the Four Corners region. This is at the Southern Ute Tribe's Ignacio site in southern Colorado. Monitoring was performed at New Mexico's Farmington site, but was discontinued in 2000. (See the CO site locations map.) All of the data are available on EPA's Air Quality System.[8] Ambient carbon monoxide levels in the Four Corners region are well below the level of the current NAAQS (see the CO trends and standards graph). Carbon monoxide levels nationwide are now very low due in large part to improved vehicle technology and emissions controls.

PM_{10} in the ambient air is, historically, the most heavily monitored pollutant in the Four Corners region. (See the PM_{10} site locations map.) Most of the monitoring has been performed using filter-based "high-volume" samplers that collect 24-hour samples and most of the data are available on EPA's Air Quality System.[8] Ambient PM_{10} levels in the Four Corners region are well below the level of the current and former NAAQS (see the PM_{10} trends graphs). As a result, some of the monitors were shut down at the end of 2006.

$PM_{2.5}$ in the ambient air has also been monitored at a number of locations in Four Corners region. (See the $PM_{2.5}$ site locations map.) Most of the monitoring has been performed using filter-based "low-volume" samplers that collect 24-hour samples and most of the data are available on EPA's Air Quality System.[8] Ambient $PM_{2.5}$ levels in the Four Corners region are well below the levels of the current NAAQS for both the 24-hour average and annual averages (see the $PM_{2.5}$ trends graphs). $PM_{2.5}$ has also been monitored as part of the IMPROVE network. These data are not on EPA's Air Quality System but may be obtained on the IMPROVE website.[9]

No monitoring for lead exists in the Four Corners region. Due to the introduction of unleaded gasoline in the 1970's, ambient lead levels have decreased to levels that are near instrument detection levels. Likewise, no monitoring exists for other pollutants such as carbon dioxide, HAPs or pesticides. While carbon dioxide is a greenhouse gas and is emitted from combustion sources, it is not considered to be toxic at typical ambient concentrations. Thus, there has been no specific reason for monitoring and no standards exist. No standards currently exist for organic compounds, including HAPs (such as volatile and semi-volatile organic compounds) and pesticides. Much of the monitoring for these compounds has been performed in urban areas where concentrations are expected to be higher, particularly for the HAPs, and more people are at risk for exposure. Several pilot and trends studies are currently underway across the nation, but the cost is very high for routine monitoring. Volatile organic compound baseline monitoring for San Juan County, New Mexico was conducted in 2004 and 2005 at three sites by the U.S. Environmental Protection Agency (EPA) Region 6. This study was primarily for ozone precursor organic compounds rather than for overall HAPs.[10,11]

Data Gaps:
Due to the very low levels of carbon monoxide, PM_{10} and $PM_{2.5}$ at existing or former air monitoring sites and at other surrounding areas, there is not expected to be any areas of the Four Corners region that need additional monitoring of these threeo pollutants to demonstrate NAAQS compliance. While there has been no monitoring for lead in the Four Corners region, the low levels that are seen nationwide and the lack of sources in the area indicate that no monitoring is likely to be needed. There is no NAAQS for carbon dioxide, so on a health basis, no monitoring is needed.

With organic compounds/HAPs and pesticides, there is little data for the area that exists. However, based on monitoring that is being performed nationwide in EPA's National Air Toxics Trends Study, there are not expected be concentrations that are much different from other areas. Due to the expense of monitoring, other areas would probably suffice as a surrogate. In addition, there are no significant major sources of HAPs in the region to warrant ambient monitoring. As part of "Ozone and Precursor Gases" suggestions, volatile organic compound/non-methane organic compound monitoring is being recommended. Pesticides may be a health issue for the agricultural population. This would lead to specific investigations rather than ambient monitoring sites.

Suggestions for Future Monitoring Work:

No suggestions for additional monitoring of carbon monoxide, PM_{10}, $PM_{2.5}$ and other common pollutants are currently being proposed.

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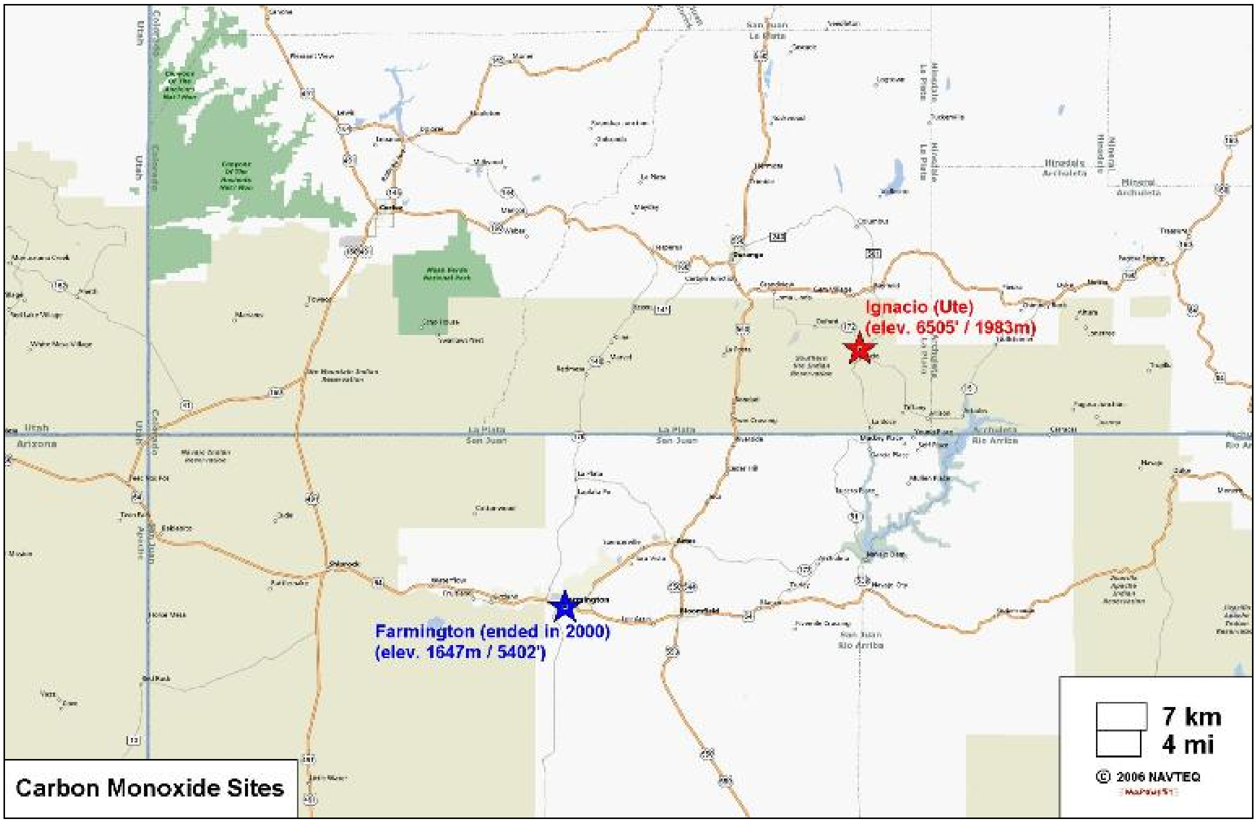
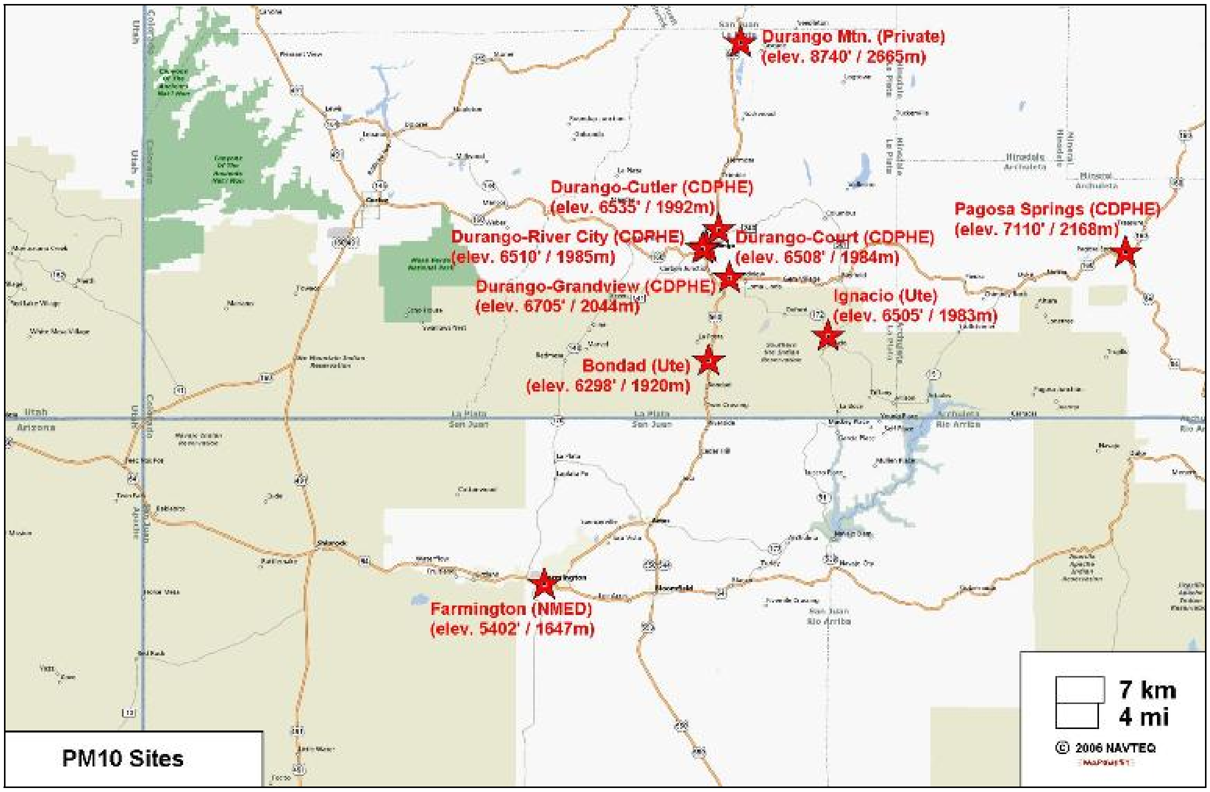
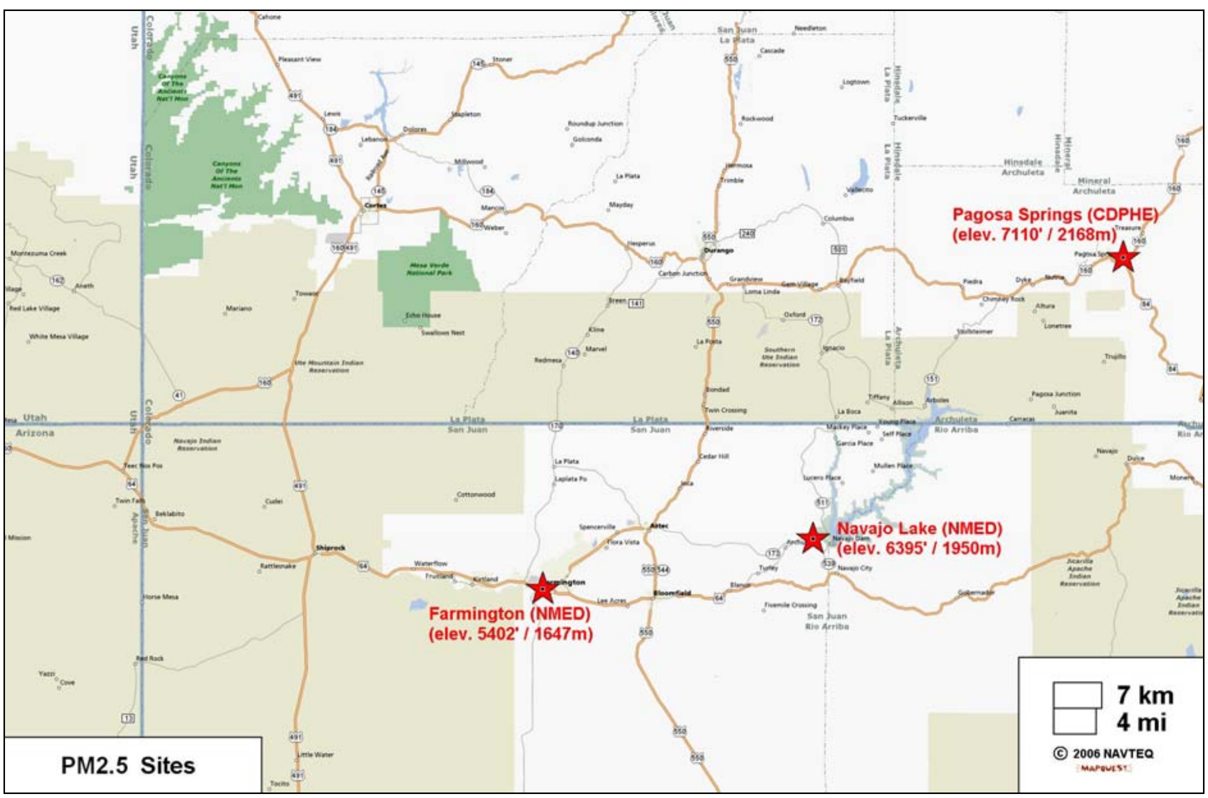
Four Corners --- Continuous Carbon Monoxide Sites in 2006

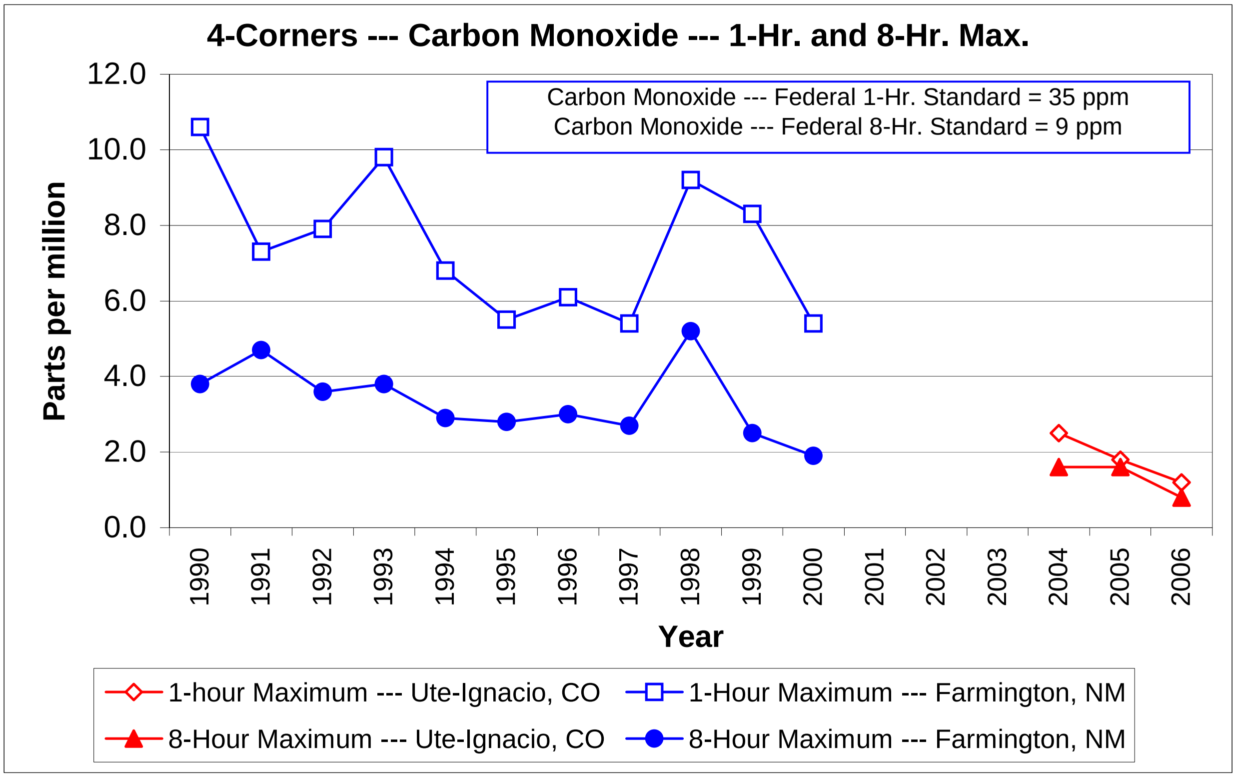


Four Corners --- Particulate Sites in 2006

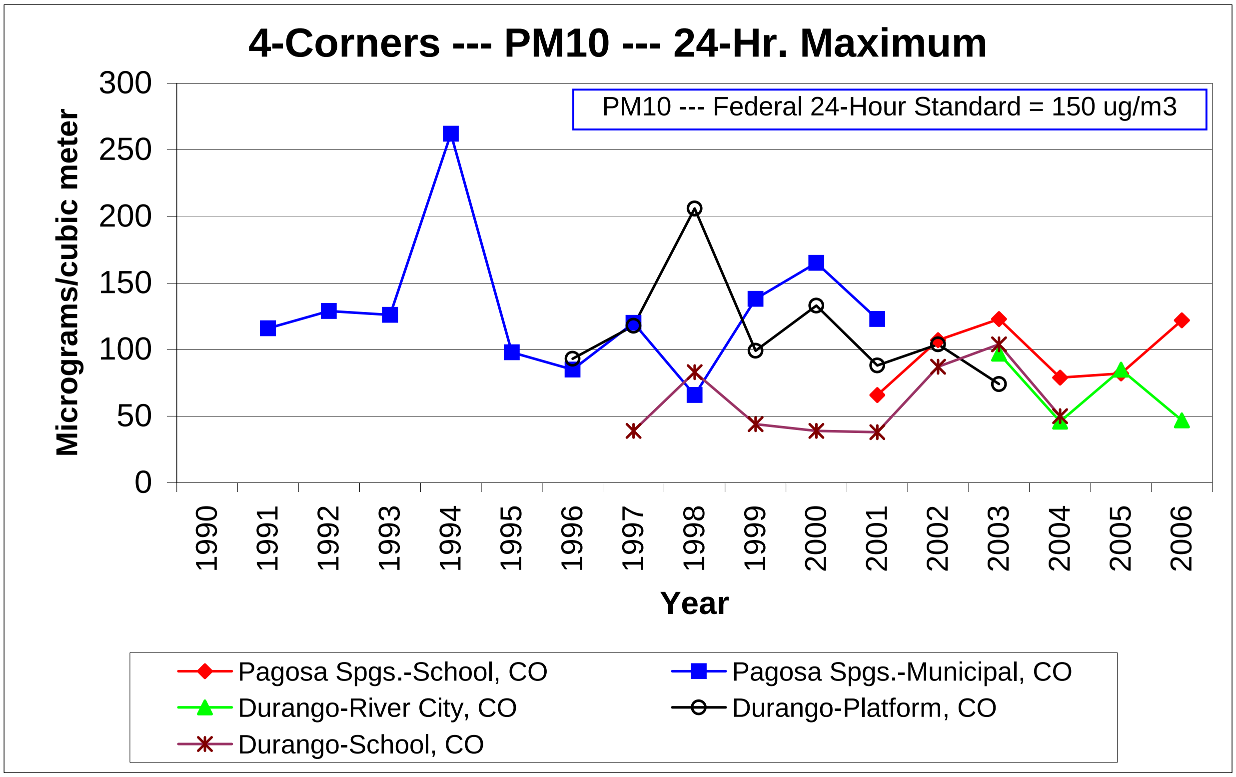


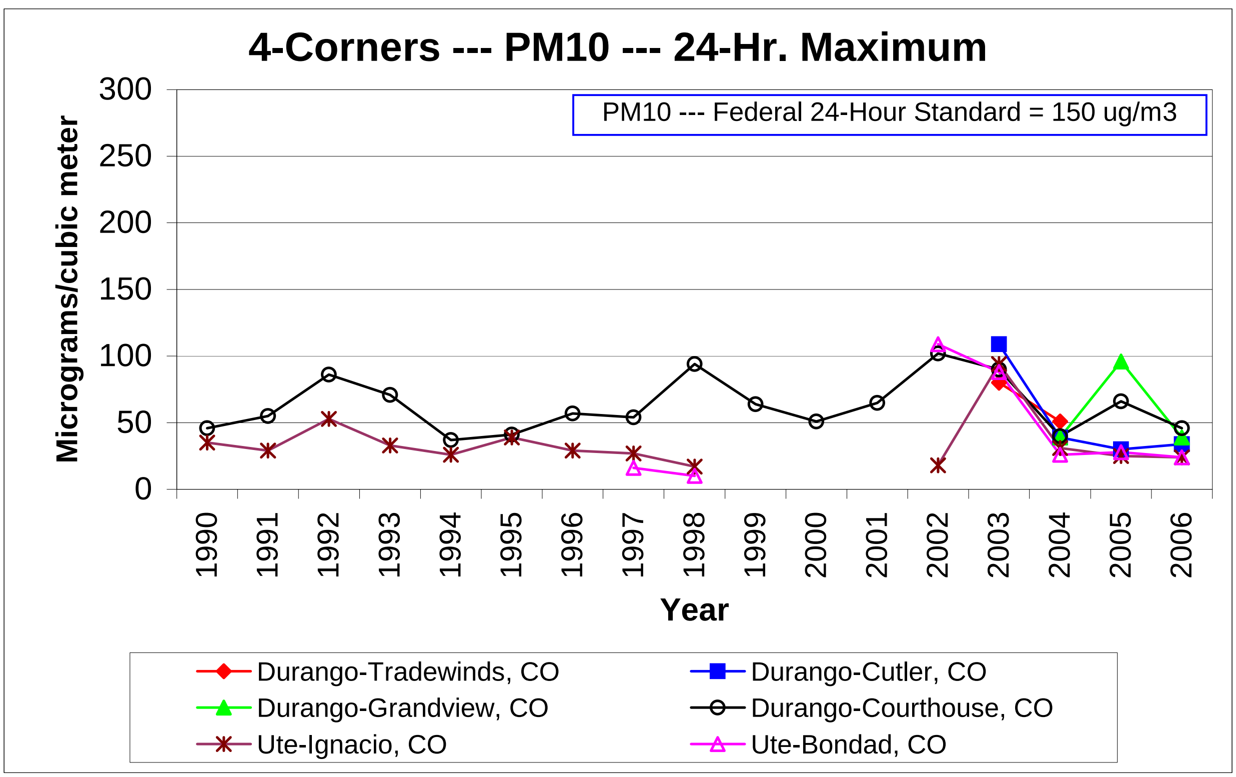


Four Corners --- Carbon Monoxide Trends (1-Hour and 8-Hour)

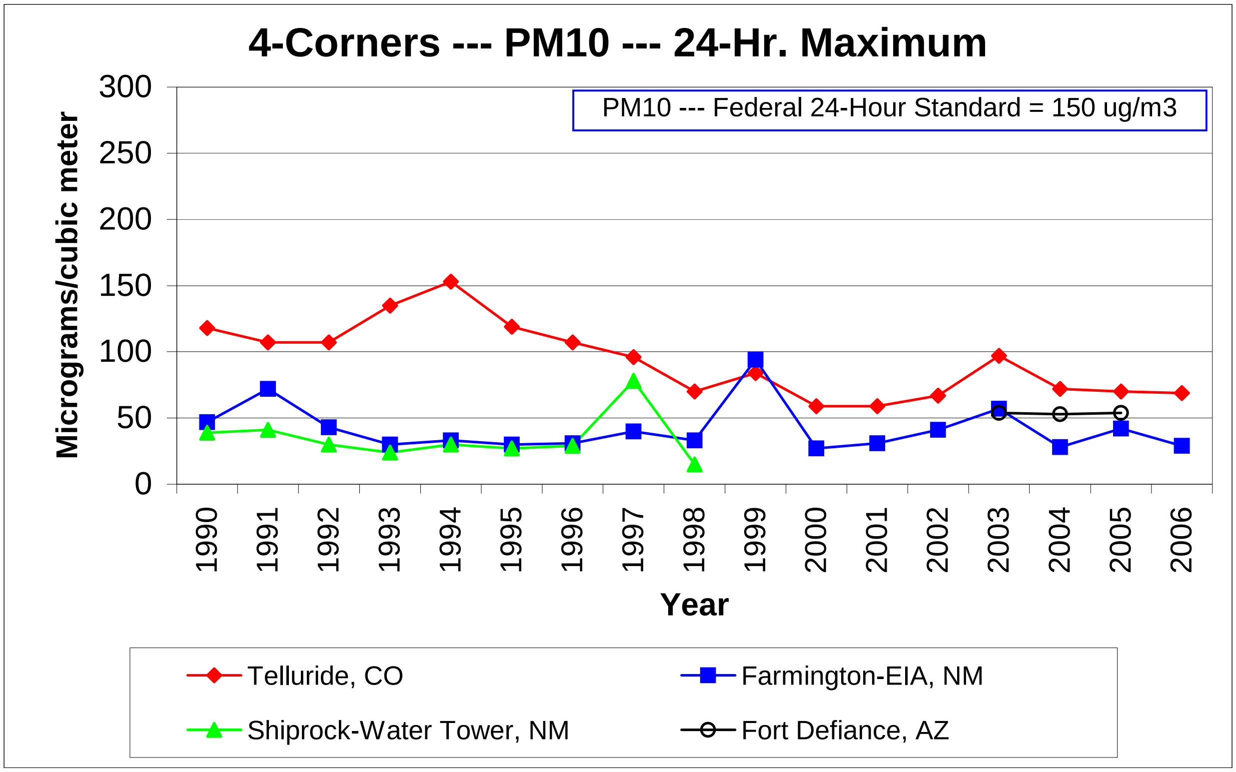


Four Corners --- PM_{10} Trends (24-Hour Maximum)

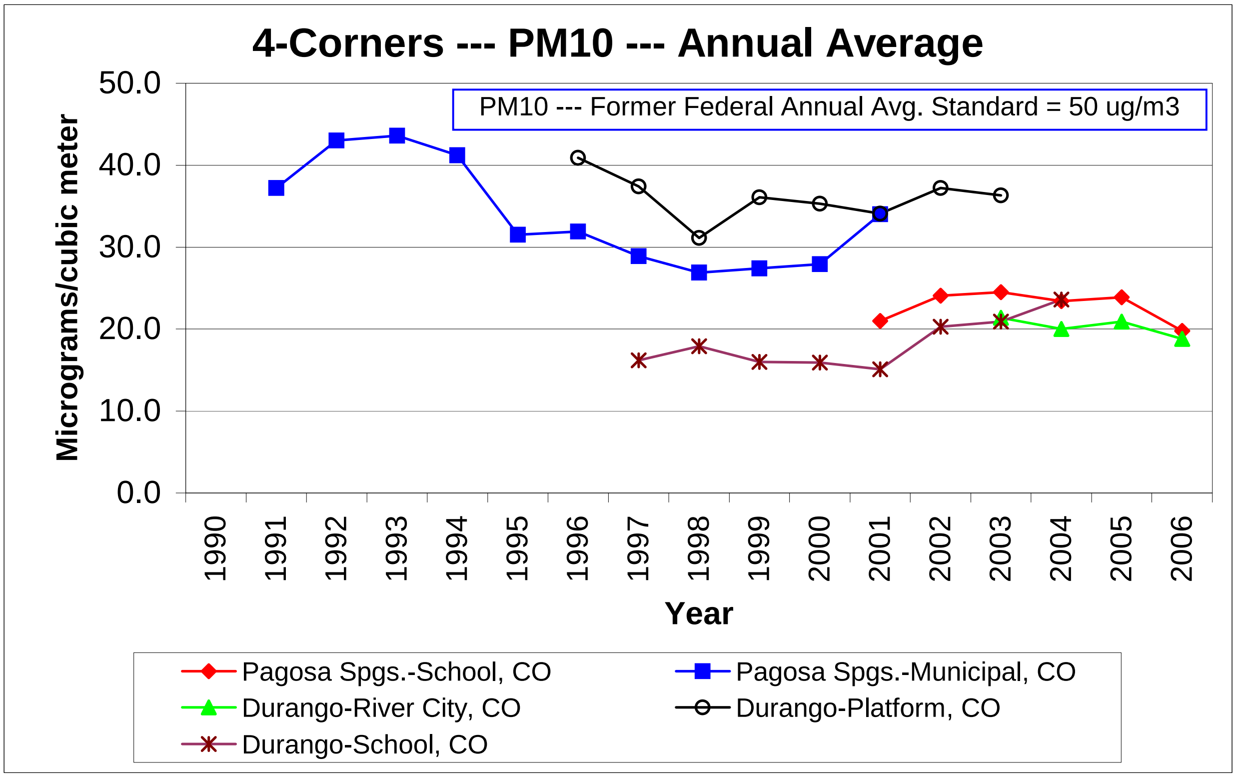


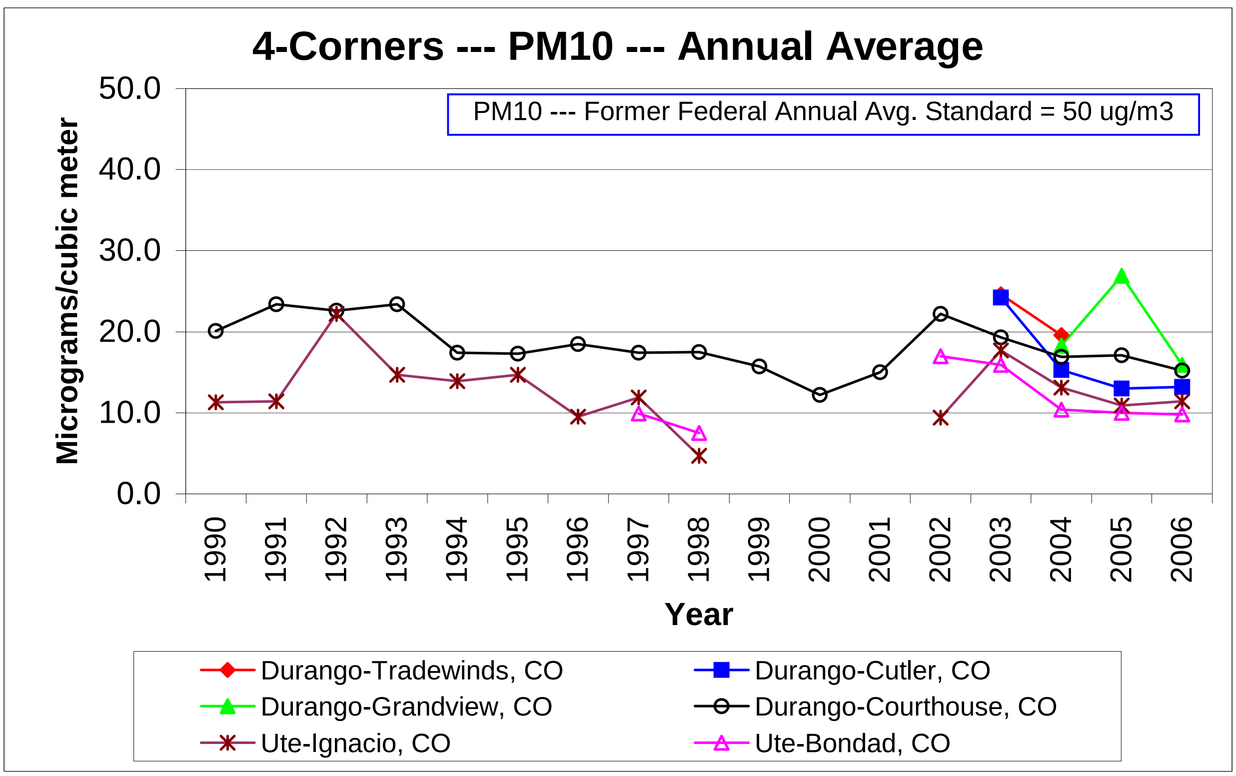


Four Corners --- PM_{10} Trends (24-Hour Maximum) – cont.

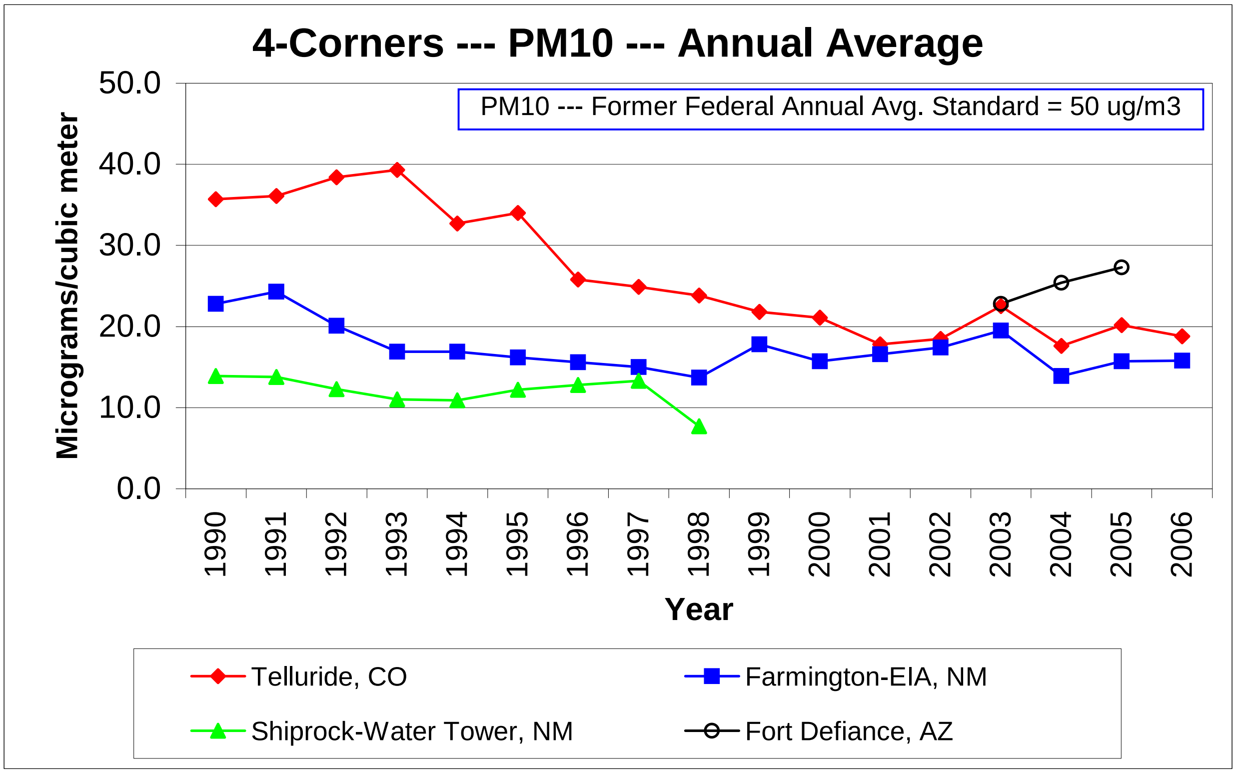


Four Corners --- PM_{10} Trends (Annual average)

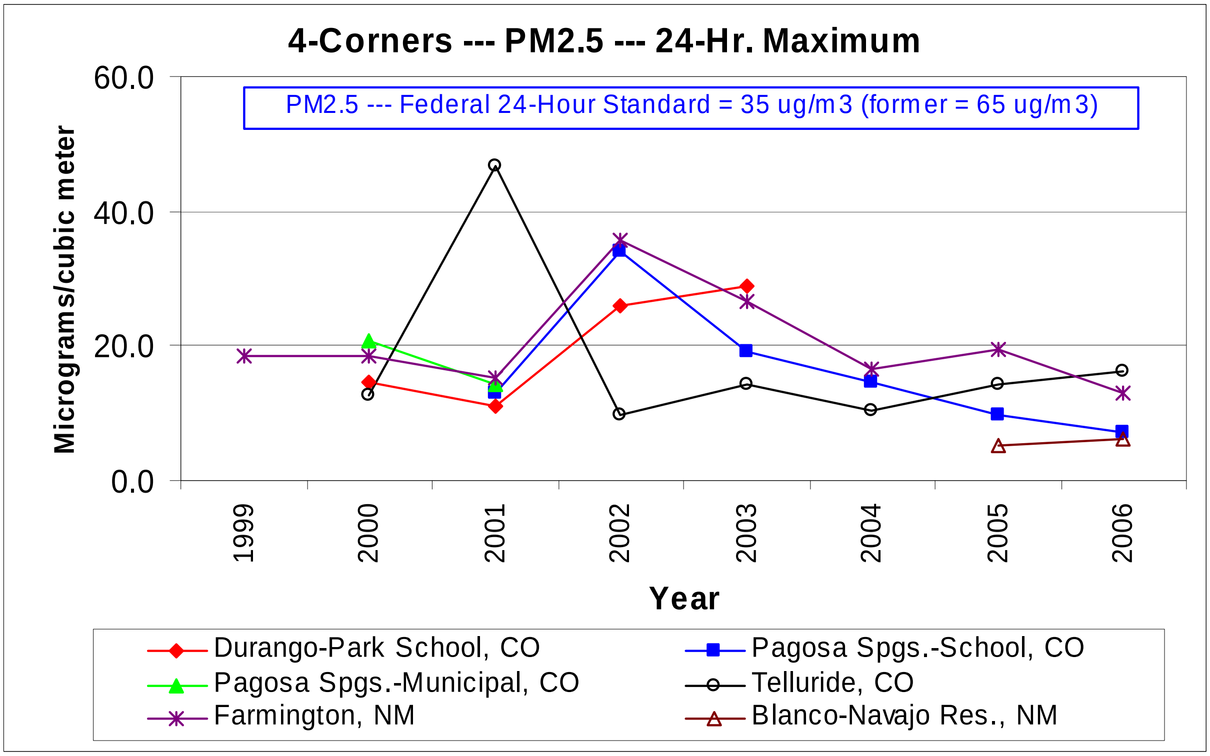




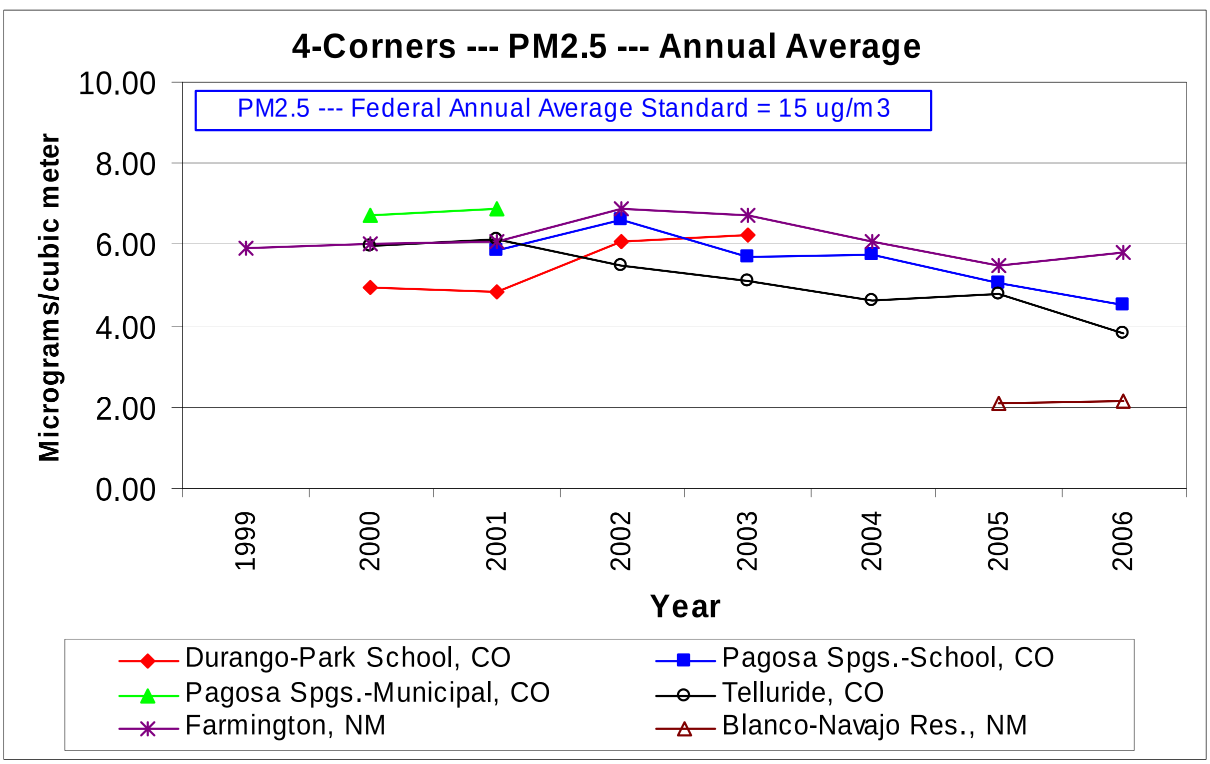
Four Corners --- PM_{10} Trends (Annual average) – cont.



Four Corners --- $PM_{2.5}$ Trends (24-Hour Maximum)



Four Corners --- $PM_{2.5}$ Trends (Annual average)



Uranium, Radionuclides and Radon

Background:

Rationale and Benefits:
Uranium is a naturally-occurring element found at low levels in virtually all rock, soil, and water. In a raw form, it is a silvery white, weakly radioactive metal. It has the highest atomic weight of the naturally occurring elements. Significant concentrations of uranium occur in some substances such as phosphate rock deposits, and minerals such as uraninite in uranium-rich ores. The largest single source of uranium ore in the United States is the Colorado Plateau region, located in Colorado, Utah, New Mexico, and Arizona.[1] Radionuclides are unstable nuclides of elements and may be natural or man-made in origin. Radon is a naturally occurring radioactive gas that is a decay product.

Uranium in soil and rocks is distributed throughout the environment by wind, rain and geologic processes. Rocks weather and break down to form soil, and soil can be washed by water and blown by wind, moving uranium into streams and lakes, and ultimately settling out and reforming as rock. Uranium can also be removed and concentrated by people through mining and refining. These mining and refining processes produce wastes such as mill tailings which may be introduced back into the environment by wind and water if they are not properly controlled. Manufacturing of nuclear fuel, and other human activities also release uranium to the environment.[2]

It is important to keep in mind that uranium is naturally present in the environment (both in air and in water) and is in your normal diet, so there will always be some level of uranium in all parts of your body.[3] The average daily intake of uranium from food ranges from 0.07 to 1.1 micrograms per day. About 99 percent of the uranium ingested in food or water will leave a person's body in the feces, and the remainder will enter the blood. Most of this absorbed uranium will be removed by the kidneys and excreted in the urine within a few days. A small amount of the uranium in the bloodstream will deposit in a person's bones, where it will remain for years.[2]

The greatest health risk from large intakes of uranium is toxic damage to the kidneys, because, in addition to being weakly radioactive, uranium is a toxic metal. Uranium exposure also increases the risk of getting cancer due to its radioactivity. Since uranium tends to concentrate in specific locations in the body, risk of cancer of the bone, liver cancer, and blood diseases (such as leukemia) are increased. Inhaled uranium increases the risk of lung cancer.[2] In addition, uranium can decay into other radioactive substances, such as radium, which can cause cancer if exposed to enough of them for a long enough period of time.[3]

The Occupational Safety and Health Administration has set occupational exposure limits for uranium in breathing air over an 8-hour workday, 40-hour workweek. The limits are 0.05 milligrams per cubic meter (0.05 mg/m^3) for soluble uranium dust and 0.25 mg/m^3 for insoluble uranium dust.[3] Uranium in drinking water is covered under the Safe Water Drinking Act, which establishes maximum contaminant levels, or MCLs, for radionuclides and other contaminants in drinking water. The uranium limit is 30 µg/l (micrograms per liter) in drinking water. The Clean Air Act limits emissions of uranium into the air where the maximum dose to an individual from uranium in the air is 10 millirem.[4] There are no Federal ambient air standards for uranium.

The isotope ^{235}U is useful as a fuel in power plants and weapons. To make fuel, natural uranium is separated into two portions. The fuel portion has more ^{235}U than normal and is called enriched uranium. The leftover portion with less ^{235}U than normal is called depleted uranium, or DU. Natural, depleted, and enriched uranium are chemically identical. Depleted uranium is the least radioactive and enriched uranium the most.[3]

Due to concerns on foreign oil dependence and global warming, renewed interest is being shown in nuclear power generation. The Colorado Plateau, as noted above, has a high concentration of uranium ore. As a result, there is increasing interest in the area for both uranium mining and milling. Of particular concern are milling operations where the mill tailings are rich in the chemicals and radioactive materials that were not removed. In the milling process, the ore is crushed and sent through an extraction processes to concentrate the uranium into uranium-oxygen compounds called yellowcake. The remainder of the crushed rock, in a processing fluid slurry, is placed in a tailings pile.[5] The most important radioactive component of uranium mill tailings is radium, which decays to produce radon.

The radium in these tailings will not decay entirely for thousands of years. Other potentially hazardous substances in the tailings are selenium, molybdenum, uranium, and thorium.[4]

In the Four Corners area, there is currently one operating uranium mill, located near Blanding Utah. A mill has also been proposed near Naturita in western Colorado. Mining operations have also been proposed in San Miguel County in Colorado. This has led to concerns over potentially increased exposures to radionuclides, radon and contaminated dusts from both mills/tailings piles and mines. Immediate concerns would be to the general public in the immediate vicinity of these facilities/operations. However, there are also concerns over longer range air transport of radionuclides, radon and contaminated dusts for the region, especially as the number of these facilities/operations may increase significantly.

Existing uranium data for the Four Corners region:
Currently, little current ambient air monitoring data exists for uranium in the Four Corners region. Neither the States of Colorado nor Utah are currently performing any monitoring around uranium mining or milling operations. From historical mining and milling, total suspended particulate and radionuclide data exist from private monitoring.

As part of National Emissions Standards for Hazardous Air Pollutant regulations (through the U.S. Environmental Protection Agency), monitoring is required to be performed to assess and limit emissions of radon and radionuclides from mines, mills and tailings.[6] U.S. Nuclear Regulatory Commission guidelines call for both onsite and offsite particulate monitoring for radionuclides, radon monitoring and meteorological monitoring at uranium mills. This monitoring is required both prior to operation and during operation.

Data Gaps:
While little ambient air monitoring data exists for uranium mine and milling operations/facilities, emissions monitoring and modeling is required under National Emissions Standards for Hazardous Air Pollutant regulations. Ambient air monitoring is required under Nuclear Regulatory Commission guidelines. Based on this, it is expected that uranium, radionuclide and radon emissions from these facilities/operations is low and should pose no threat to the general public either locally or at a distance. However, as additional facilities become operational, the overall uranium, radionuclide and radon emissions in the Four Corners area will increase and may be significant.

Recommendations:

No recommendations for additional ambient air monitoring of uranium, radionuclides or radon are currently being proposed. However, as uranium mining and milling activities in the Four Corners region increase, this topic may need to be revisited.

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Mercury

Background:

Rationale and Benefits: Methyl mercury is a known neurotoxin affecting humans and wildlife. Coal-fired power plants are the number one source of mercury emissions in the United States[1]. The Four Corners already is home to several power plants that are large emitters of mercury and additional coal-powered plants are proposed for the region. Individuals and community groups in the Four Corners region have expressed great concern about mercury emissions in our region and the existing mercury fish consumption advisories in several reservoirs. Studies of mercury in air deposition, the environment and in sensitive human populations (such as pregnant women) are necessary to set a baseline for current levels and to detect future impacts of increased mercury emissions on these sensitive human populations and natural resources, including the Weminuche Wilderness and Mesa Verde National Park, which are both Federal Class I Areas.

Existing mercury data for the Four Corners region: Total mercury in wet deposition has been monitored at Mesa Verde National Park since 2002 as part of the Mercury Deposition Network (MDN)(Figure 1)[2]. Results show mercury concentrations among the highest in the nation during certain years. Precipitation is relatively low, however, so mercury in wet deposition is moderate (Figure 3)[2]. Mercury concentrations have been measured in snowpack at a few sites in the San Juan Mountains by the USGS and moderate concentrations similar to the Colorado Front Range have been recorded[3]. Mercury concentrations in sport fish from several reservoirs have exceeded the 0.5 microg/g action level resulting in mercury fish consumption advisories for water bodies including McPhee, Narraguinnep, Todden, Navajo, Sanchez and Vallecito Reservoirs and segments of the San Juan River (Figure 4)[4]. Sediment core analysis for Narraguinnep Reservoir show that mercury fluxes increased by approximately a factor of two after about 1970[5]. Finally, atmospheric deposition just to the surface of McPhee and Narraguinnep Reservoirs (i.e., not including air deposition to the rest of the watershed) is estimated to contribute 8.2% and 47.1% of total mercury load to these water bodies, respectively[6].

Data Gaps: Very little data exists for the Four Corners Region with which to assess current risks and trends over time for mercury in air deposition, ecosystems, and sensitive human populations. No data exists for mercury in deposition at high elevations. Wet deposition of mercury at Mesa Verde National Park may not portray the situation in the mountains where mercury may be deposited at higher concentrations and total amounts because of greater rates of precipitation and the process of cold condensation, which causes volatile compounds to migrate towards colder areas at high elevation and latitude[7]. No information about total mercury deposition from the atmosphere (i.e., including dry deposition) exists for low or high elevations in the Four Corners Region. Furthermore, analysis of sources of air deposition of mercury is lacking. Except for a handful of reservoirs, no information exists for incorporation of mercury into aquatic ecosystems and subsequent effects on food-webs. No systematic effort exists to document mercury impacts in a wide range of water bodies over space and time. Lastly, impacts of mercury exposure to human populations are unknown.

Three new studies have begun or will begin in 2007, however. The Mountain Studies Institute (MSI) will measure total mercury in bulk atmospheric deposition (collector near NADP station at Molas Pass, 10, 659 ft. elevation), in lake zooplankton (invertebrates eaten by fish), and in lake sediment cores in the San Juan Mountains, a project funded by the U.S. EPA and USFS[8]. Dr. Richard Grossman is measuring mercury levels in hair collected from pregnant women in the Durango vicinity. Lastly, the Pine River Watershed Group (via the San Juan RC&D) recently was granted start-up funds from La Plata County to initiate event-based sampling of mercury in atmospheric deposition at Vallecito Reservoir and accompanying back-trajectory analyses to locate the source of these storm events.

Suggestions for Future Monitoring Work:

1. Install and operate a long-term monitoring station for mercury in wet deposition for a location at high elevation where precipitation amounts are greater than the site at Mesa Verde NP. Co-location of the collector with the NADP site at Molas Pass would provide data pertinent to Weminuche Wilderness and the headwaters of Vallecito Reservoir. This monitor would be part of the Mercury Deposition Network (MDN). Upgrading the

NADP monitoring equipment at Molas Pass to include the MDN specifications would cost $5,000 to $6,000, while annual monitoring costs are $12,112 plus personnel as of September 2006.

2. Install and operate a long-term monitoring station for mercury in total deposition (wet and dry) for at least one MDN station in the Four Corners Region. Speciated data will be collected and analyzed as is feasible. The MDN is currently developing this program and costs are anticipated at about $50,000 per year.

3. Support multi-year comprehensive mercury source apportionment study to investigate the impact of local and regional coal combustion sources on atmospheric mercury deposition. This type of study would require additional deposition monitoring (i.e., suggestions 1 & 2 above). Speciated data will be collected and analyzed as is feasible. A mercury monitoring and source apportionment study was recently completed for eastern Ohio. (http://pubs.acs.org/cgi-bin/asap.cgi/esthag/asap/html/es060377q.html9). Costs TBD.

Support a study of mercury incorporation and cycling in aquatic ecosystem food-webs, including total and methyl mercury in the food-webs of lakes and wetlands. This option includes studies that determine which ecosystems currently have high levels of total and methyl mercury in food-web components, how mercury levels in ecosystems change over time, where the mercury is coming from, and what conditions are causing the mercury to become methylated (the toxic form of mercury that bio-accumulates in food-webs). This information would allow tracking of mercury risks over time and space and serves as the basis for predicting future impacts. Existing reservoir studies and the upcoming MSI investigation serve as a starting point to build a collaborative and systematic approach. Costs TBD.

Support continued studies of mercury concentrations in sensitive human populations in the region to understand what exposure factors increase likelihood of unhealthy mercury levels in the body. Dr. Richard Grossman's study serves as a starting point to continue this effort. Costs TBD.

Form a multi-partner Mercury Advisory Committee that would work collaboratively to prioritize research and monitoring needs, develop funding mechanisms to sustain long-term mercury studies, and work to communicate study findings to decision-makers. The Committee would include technical experts and stakeholder representatives from States, local governments, land management agencies, watershed groups, the energy industry, etc.

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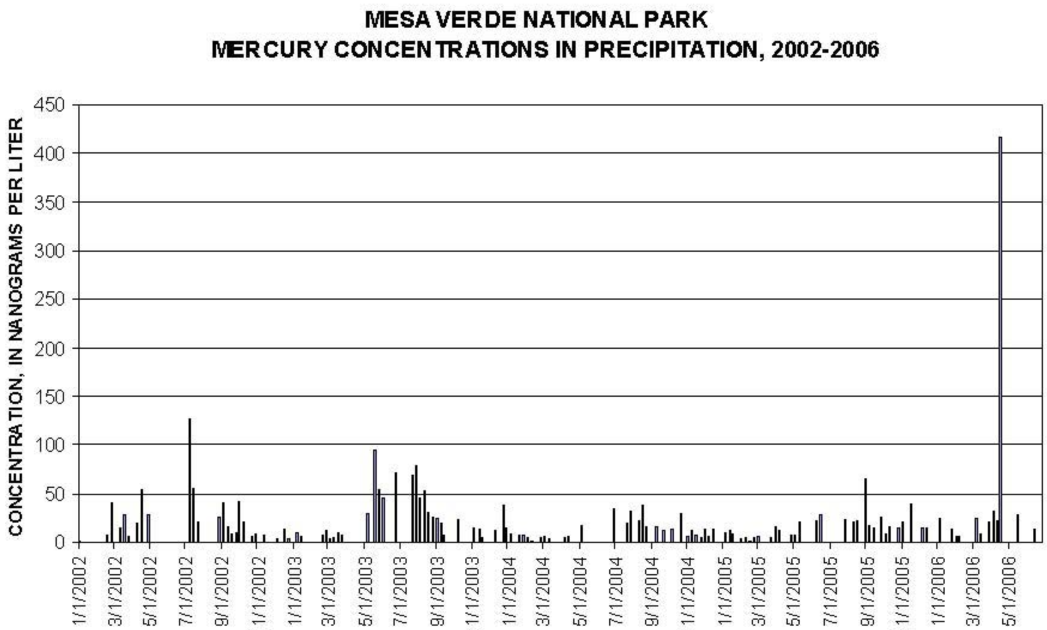
Figures



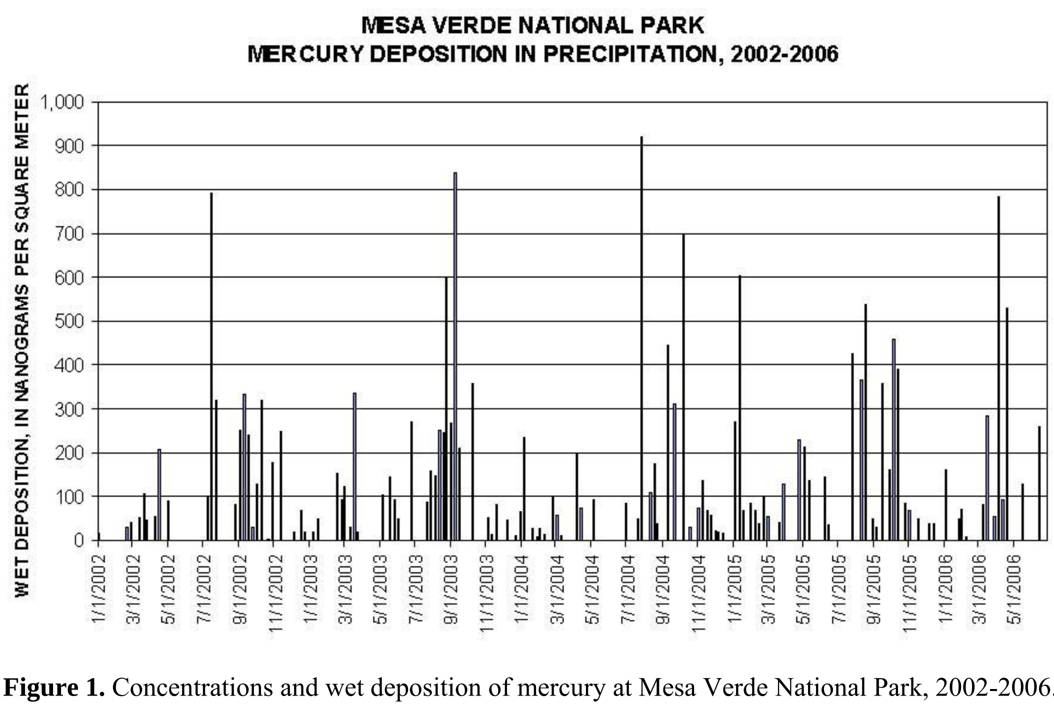


Figure 1. Concentrations and wet deposition of mercury at Mesa Verde National Park, 2002-2006. Data are from the National Atmospheric Deposition Program, Mercury deposition Network.

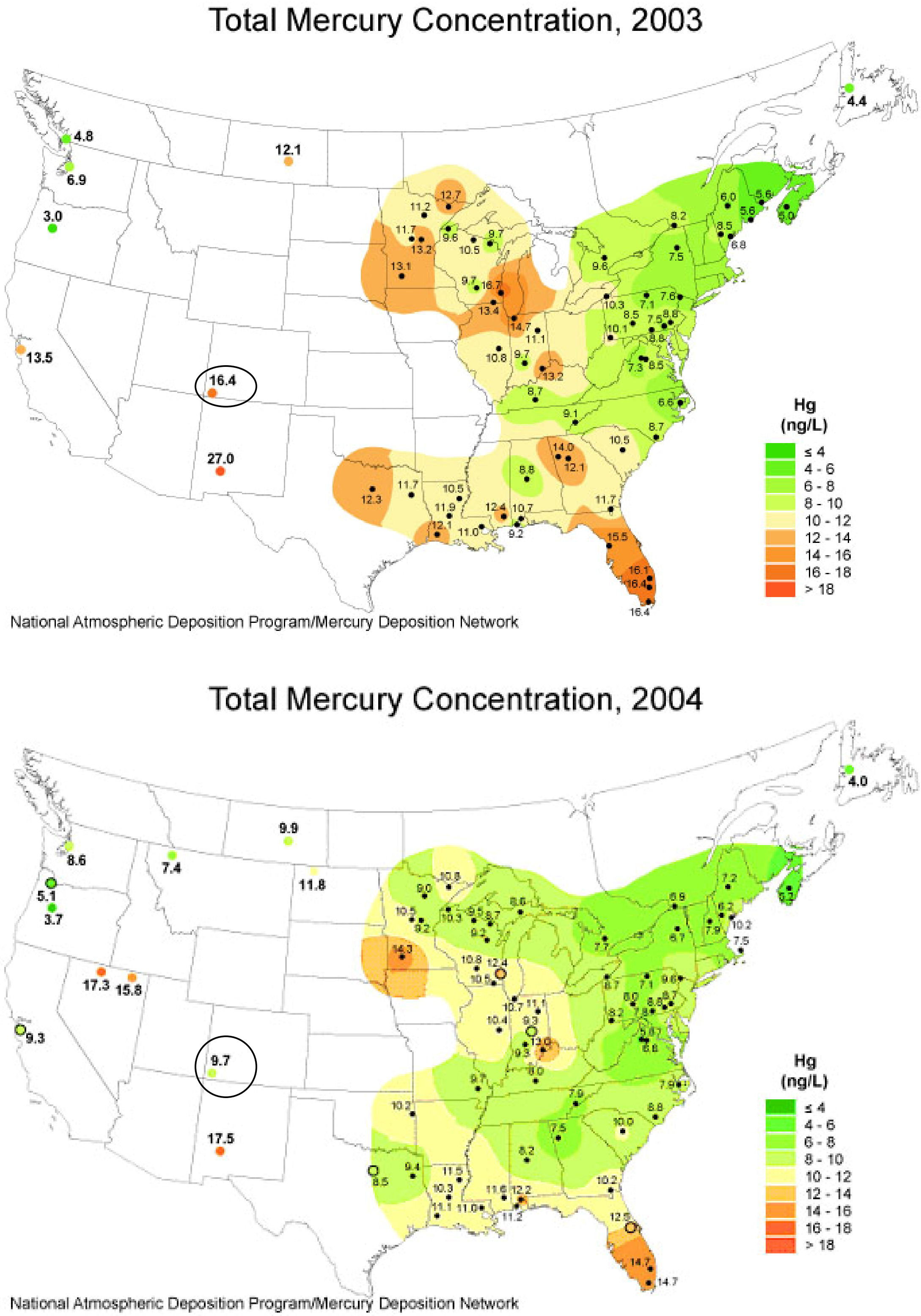
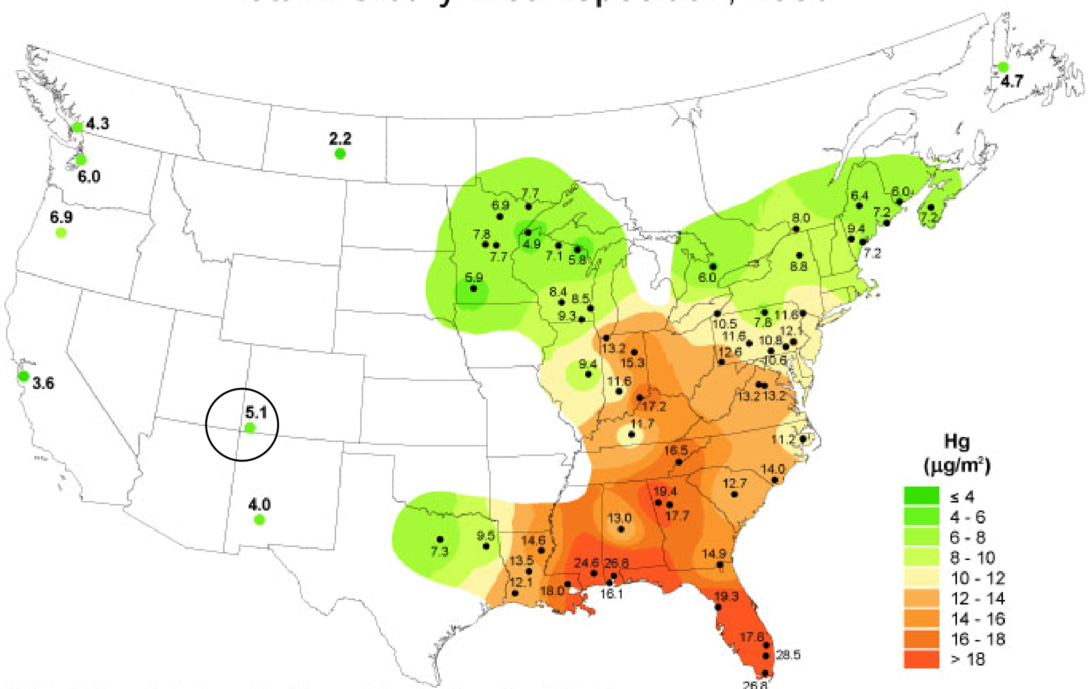


Figure 2. Volume-weighted mean concentrations of mercury in wet deposition at MDN monitoring stations across the United States for 2003 (top) and 2004 (bottom). Mesa Verde National Park is circled.

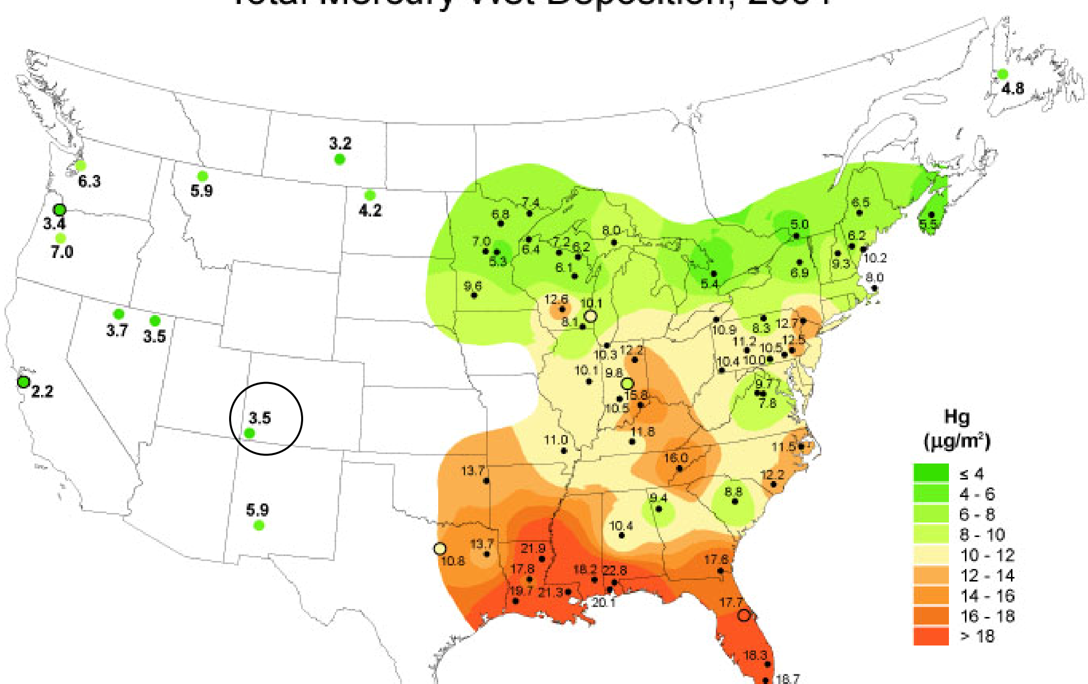
The years 2003 and 2004 represent “high” and “low” average annual concentrations for the Park’s short data record, 2002-2006.

Total Mercury Wet Deposition, 2003



National Atmospheric Deposition Program/Mercury Deposition Network

Total Mercury Wet Deposition, 2004



National Atmospheric Deposition Program/Mercury Deposition Network

Figure 3. Total mercury wet deposition at MDN monitoring stations across the United States for 2003 (top) and 2004 (bottom). Mesa Verde National Park is circled. While concentrations are high (Figure 2), total wet deposition of mercury is low to moderate due to low precipitation amounts at Mesa Verde.

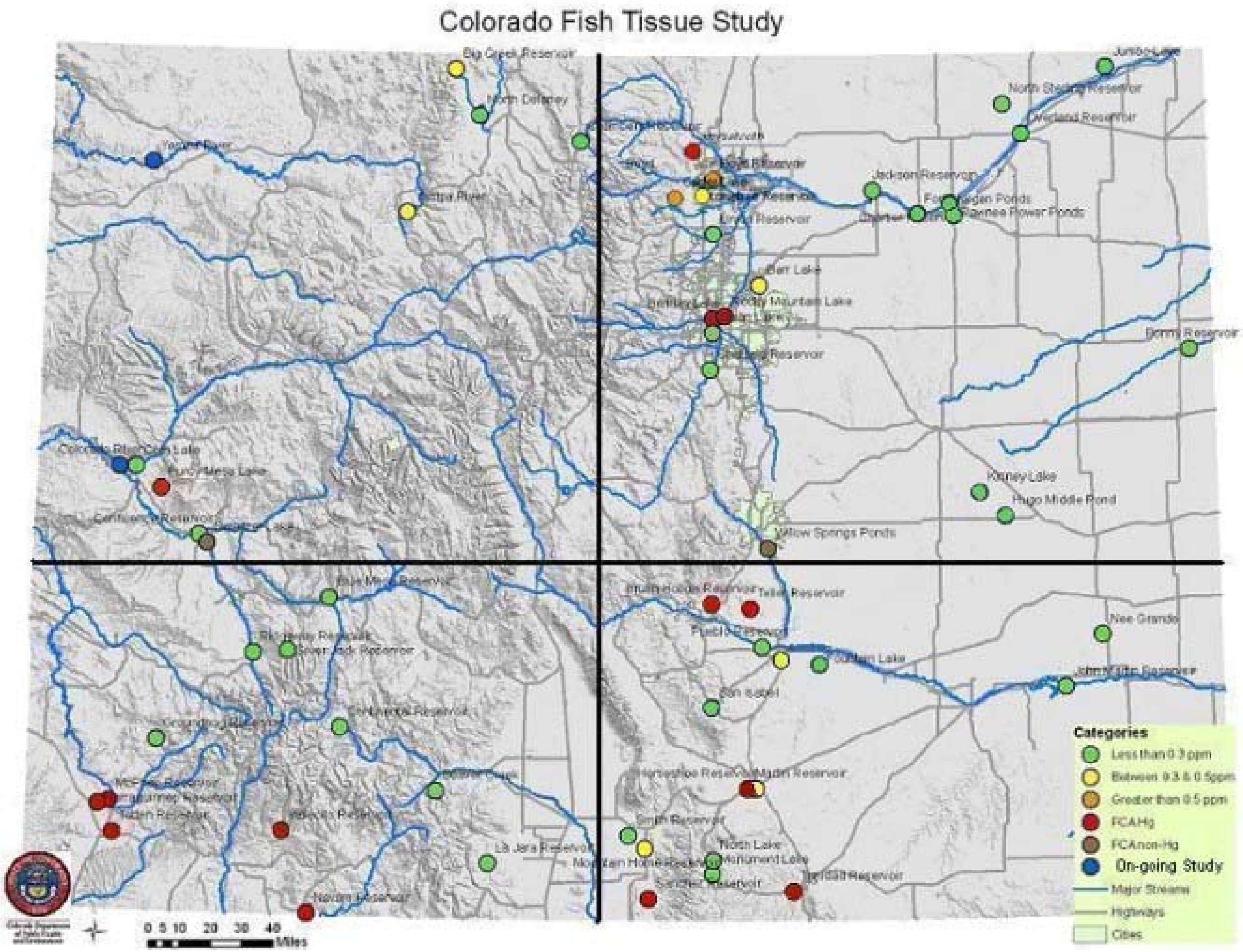


Figure 4. Results of a study by the Colorado Department of Public Health and Environment (CDPHE) measuring mercury concentrations in fish tissue in selected water bodies. The sites marked in red already have consumption advisories posted on them. Advisories are triggered by having a mercury level of 0.5 parts per million or more. The sites in orange have a similar mercury concentration to the red and are in the process of having consumption advisories posted on them as well. The sites marked in yellow have mercury levels between 0.5ppm and 0.3ppm. These are water bodies that the CDPHE is keeping a close watch on, although they are not recommending restricting consumption. The sites marked in green have mercury concentrations below 0.3ppm. The green sites are also not recommended for restricted consumption. Figure from CDPHE's Colorado Fish Tissue Study, [http://www.cdphe.state.co.us/wq/FishCon/analyses/index.html.](http://www.cdphe.state.co.us/wq/FishCon/analyses/index.html)

Atmospheric Deposition of Nitrogen and Sulfur Compounds

<u>Background:</u>

Rationale:

Nitrogen (N) is an essential nutrient, but in elevated amounts it can cause harmful effects to ecosystems and human health. In areas with minimal human development, N in air deposition is a major contributor to N inputs to ecosystems, including surface waters. Air deposition includes wet deposition received with precipitation, but also includes dry deposition of gases and aerosols, through fall deposited under forest canopies, and condensation of cloud and fog. Atmospheric N mainly is deposited as nitrate, nitric acid, ammonium, and dissolved organic nitrogen. Key anthropogenic sources include nitrogen oxides (NOx) emitted from fossil fuel burning and ammonia volatized from fertilizer and animal wastes. NOx also will react with volatile organic compounds to form ozone (see ozone sub-chapter). Increased deposition of atmospheric N can result in high levels of nitrate in surface and ground water, shifts in species, decreased plant health, and eutrophication (i.e., fertilization) of otherwise naturally low-productivity ecosystems. Both N and sulfur (S) oxides can form "acid rain" and lead to acidification of surface and groundwater and soils. S oxides primarily are emitted to the atmosphere by burning of fossil fuels.

Atmospheric deposition of S has decreased at many monitoring stations in the USA, especially in the eastern portion, since the implementation of the Clean Air Act Title IX Amendments. Despite a few locations with slight increases in S, amounts and concentrations of sulfate in wet deposition generally are low in the western USA. In contrast, concentrations of nitrate and ammonium in wet deposition have increased at some monitoring stations in the USA, including many in the western portion (Figures 1-3).[1, 2]

Harmful ecological effects of elevated N deposition have been documented in the western United States in regions downwind of emissions hotspots, including both high and low-elevation ecosystems[3]. These effects include high nitrate concentrations in streams and lakes, reduced clarity of lakes, altered and less diverse aquatic algal and terrestrial plant communities, loss of N from soils via leaching and gas flux, increased invasive species, changed forest carbon cycle and fuel accumulation, altered fire cycles, harm to threatened and endangered species, and contribution to regional haze and ozone formation[3]. In the Colorado Front Range, including the east side of Rocky Mountain National Park, harmful ecosystem effects attributed to increased N deposition specifically include: chronically elevated levels of nitrate in surface waters, altered types and abundances of aquatic algal species (diatoms), elevated levels of N in subalpine forest foliage, long-term accumulation and leaching of N from forest soils, and shifts in alpine plants from wildflowers to more grasses and sedges[3,4,5]. Hindcasting of deposition trends estimate that the harmful effects in the CO Front Range began when N in wet deposition increased above the 1.5 kg/ha/yr threshold[6]. An ecological critical load is the quantitative estimate of an exposure to one or more pollutants below which significant harmful effects on specified sensitive elements of the environment do not occur according to present knowledge[7]. Rocky Mountain National Park has adopted 1.5 kg/ha/yr of N in wet deposition as its ecological critical load[8] and the Colorado Department of Public Health and Environment's Air Pollution Control Division is now working to reduce N deposition loads to the Park[9].

<u>Existing N & S deposition and ecological effects data for the Four Corners and San Juan Mountain region:</u>

Currently, monitoring stations for N, S, and H+ in wet deposition exist at Mesa Verde National Park (since 1981), Molas Pass (since 1986), and Wolf Creek Pass (since 1992) as part of the National Atmospheric Deposition Program (NADP)[10]. Dry deposition of N and S, which is especially important in arid regions (Fenn et al. 2003), has been monitored since 1995 at Mesa Verde NP as part of the Clean Air Status and Trends Network (CASTNet). Concentrations of airborne aerosols such as ammonium nitrate and ammonium sulfate are reported as part of the Interagency Monitoring of Protected Visual Environments (IMPROVE) program at Mesa Verde National Park and a site near Durango Mountain Resort (Weminuche Wilderness).

Trends of sulfate concentrations in wet deposition show either a decrease over time or no change at monitoring stations in the vicinity of the Four Corners region. Conversely, trends of nitrate and ammonium concentrations in wet deposition appear to be stable or increasing (Figure 4)[10,11]. In general, N in wet deposition in the Four Corners and San Juan Mountain region currently is at or above the 1.5 kg/ha/yr ecological critical load discussed above for

Rocky Mountain National Park. Dry deposition data from Mesa Verde NP indicate that, for the period 1997-2000, dry deposition contributed about half of the total inorganic nitrogen deposition and about one-third of the total sulfur deposition. The short data record is insufficient to detect trends over time for dry deposition. Model simulations of total wet plus dry deposition of N in the western United States indicate a possible hotspot for N deposition in SW Colorado (Figure 5)[12].

Inorganic water chemistry for Wilderness Lakes has been collected by the USDA-National Forest Service and US Geological Survey and over 15 years of data have accumulated for some lakes. While some of this data has been compared to high-elevation lake water chemistry in other regions of Colorado and Wyoming[13], a full analysis has not been completed. Furthermore, the data are insufficient to detect potential changes to lake biology.

Data Gaps: While data for N in wet deposition exist from multiple sites in the region, dry deposition is studied only at Mesa Verde National Park, which does not represent higher-elevations common near the Four corners region. Data concerning ecological effects of N deposition are very sparse for both high and low elevations and the limited data that do exist have not been analyzed adequately. No data exists for N and S deposition in the vicinity of emission sources. For example, no monitoring of N and S in wet or dry deposition occurs in NW New Mexico with the exception of Bandelier National Park.

Suggestions for Future Monitoring Work:

C. Continue monitoring for N, S and H+ in wet deposition via the NADP at the Molas Pass, Wolfe Creek Pass and Mesa Verde National Park sites. Consider adding a site closer to emissions sources in NW New Mexico.

D. Initiate long-term monitoring / modeling of N and S in dry deposition via the Clean Air Status and Trends Network (CASTNet) at a site such as Molas Pass, which is at higher elevation than the one existing site at Mesa Verde NP. Consider adding an additional site closer to emissions sources in NW New Mexico.

E. Complete a full analysis of existing Wilderness Lakes data, including spatial and temporal trends and correlation of measurements with watershed or lake characteristics.

F. Support a suite of ecological studies in order to measure potential harmful effects of N deposition on natural resources across an elevation gradient. The studies should include an observational component aimed at documenting changing ambient conditions, but experimental manipulations should also be used to understand cause and effect relationships in addition to potential future responses. These studies should be modeled after those conducted in the Colorado Front Range, California, etc. (see Fenn et al. 2003)[3].

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Figures

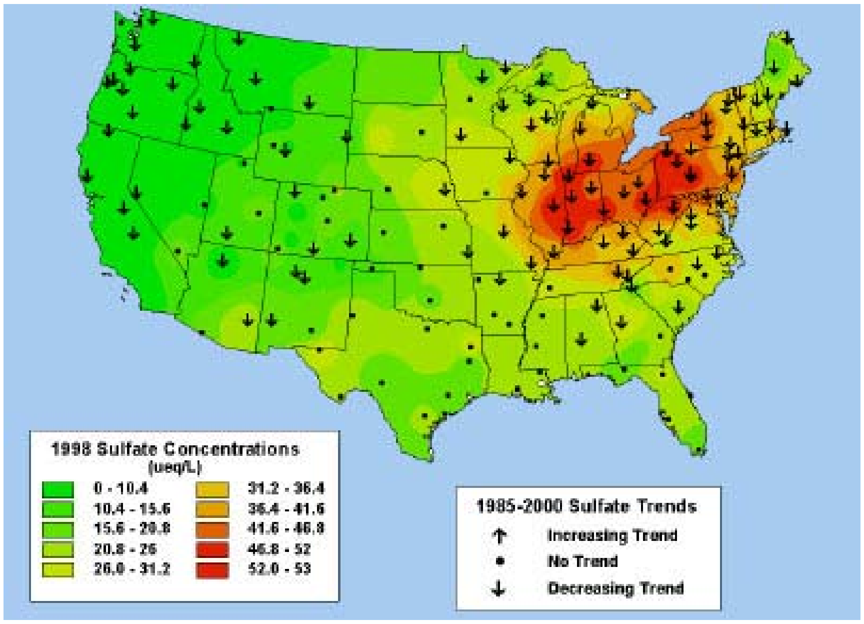


Figure 1. Trends in sulfate concentrations in wet deposition, 1985-2000. Sulfate concentrations are low in the Four Corners region and either show no trend or a decreasing trend over time[2]

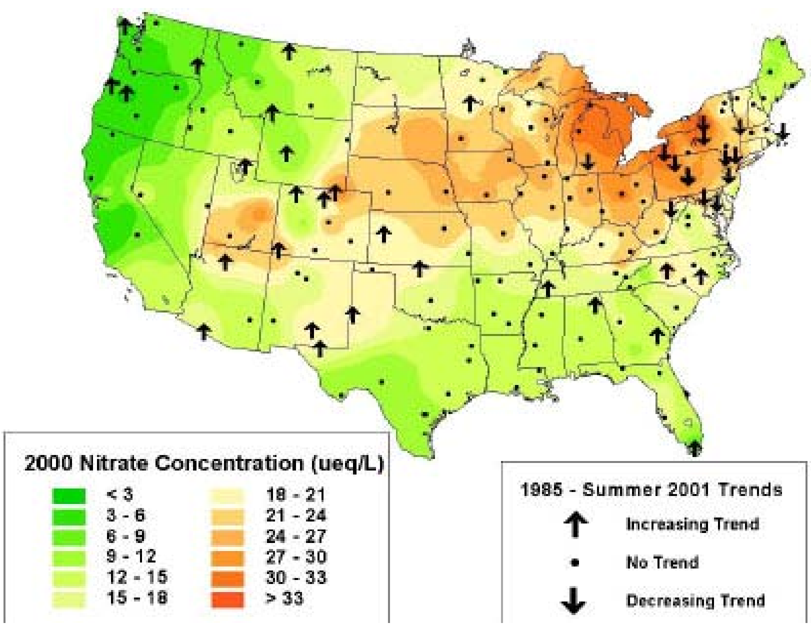


Figure 2. Trends in nitrate concentrations in wet deposition, 1985-2001. Nitrate concentrations are moderate in the Four Corners Region and show either no trend or an increasing trend over time.[2]

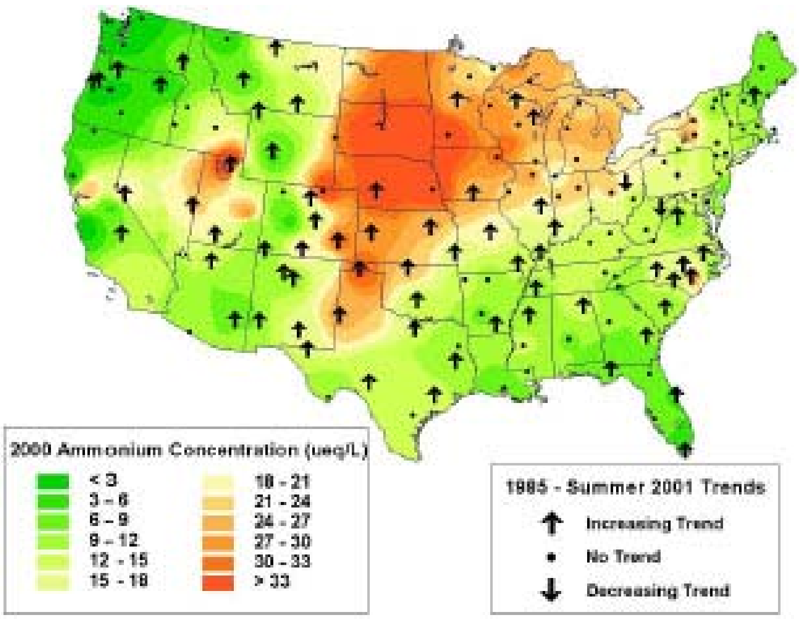


Figure 3. Trends in ammonium concentrations in wet deposition, 1985-2001. Ammonium concentrations are low in the Four Corners Region but show an increasing trend over time.[2]

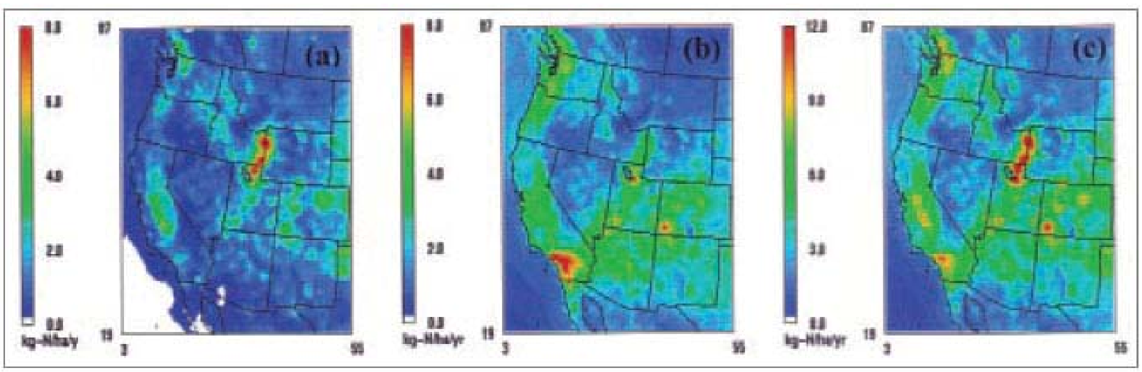
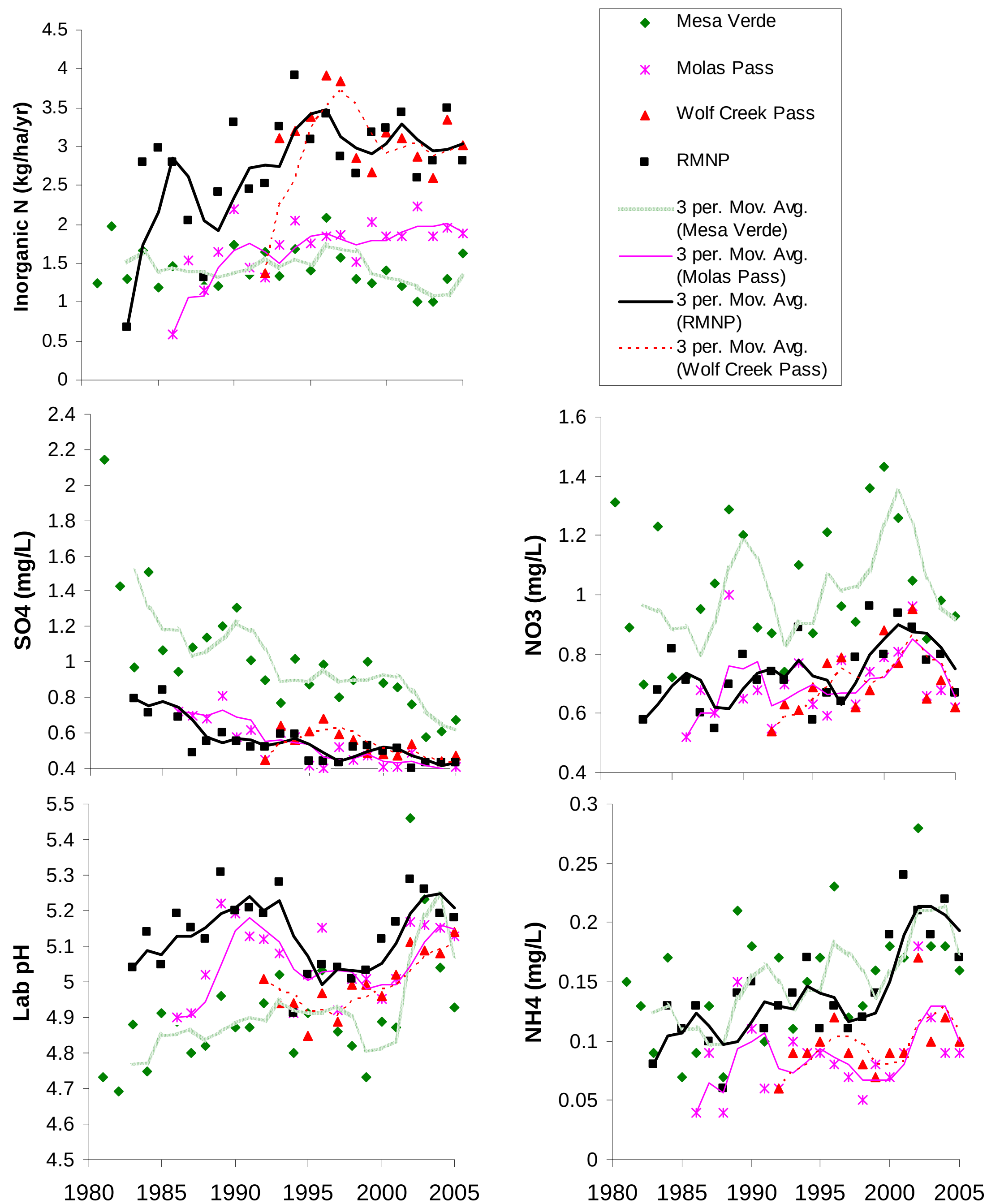


Figure 4. Model-simulated annual nitrogen deposition (kg/ha/yr) in the western United States in 1996 for (a) total wet and dry deposition of N from ammonia and ammonium, (b) total wet and dry deposition of N from nitric oxide, nitrogen dioxide, nitric acid, and nitrate, and (c) total N deposition calculated as the sum of (a) and (b).[13]

Figure 5. Annual averages of total inorganic nitrogen, pH, and sulfate nitrate, and ammonium concentrations in wet deposition from Mesa Verde National Park, Molas Pass, Wolf Creek Pass, and Rocky Mountain National Park (RMNP). Concentrations are precipitation volume-weighted means. Trend lines are 3 period moving averages and are not meant to indicate presence or absence of statistical trends. RMNP is included for comparison as a location where ecological effects of nitrogen deposition are documented.



Additional figures for Mesa Verde National Park based on data from the National Atmospheric Deposition Program:

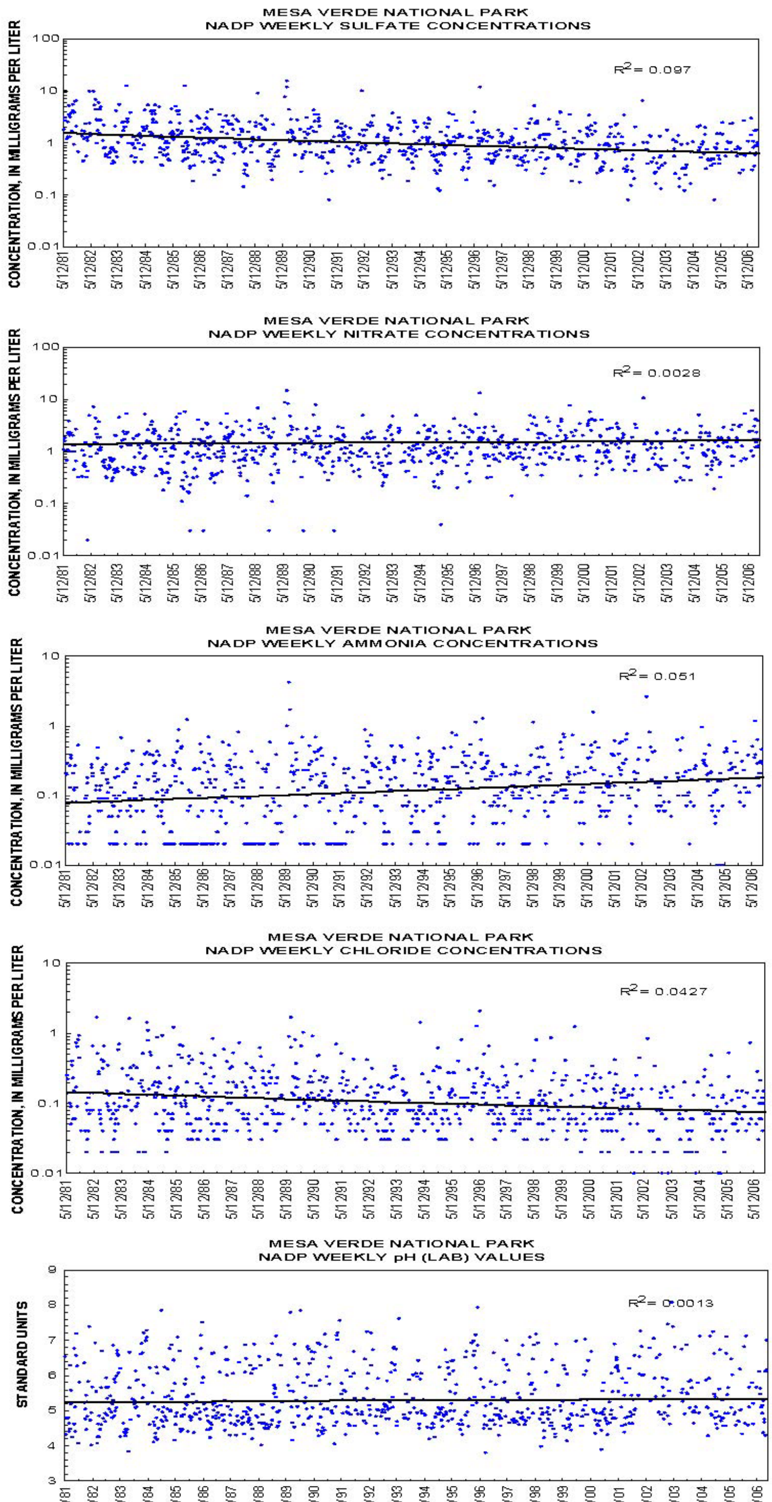


Figure 1. Weekly concentrations of selected constituents in wet deposition at Mesa Verde National Park, 1981-2006. Data are from the National Atmospheric Deposition Program.

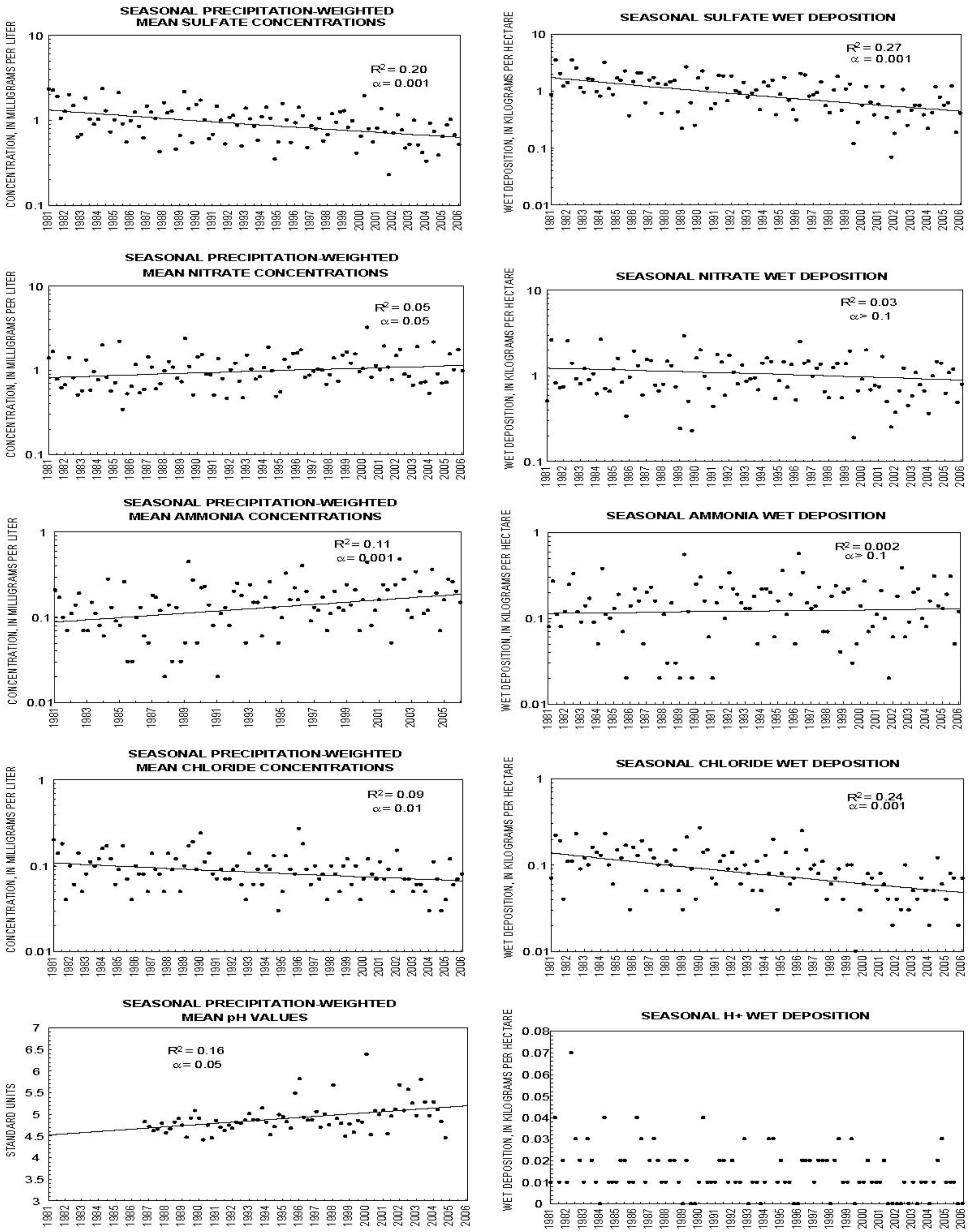


Figure 2. Seasonal concentrations and wet deposition of selected constituents at Mesa Verde National Park, 1981-2006. Data are from the National Atmospheric Deposition Program. Significance (α) from Mann-Kendall trend test.

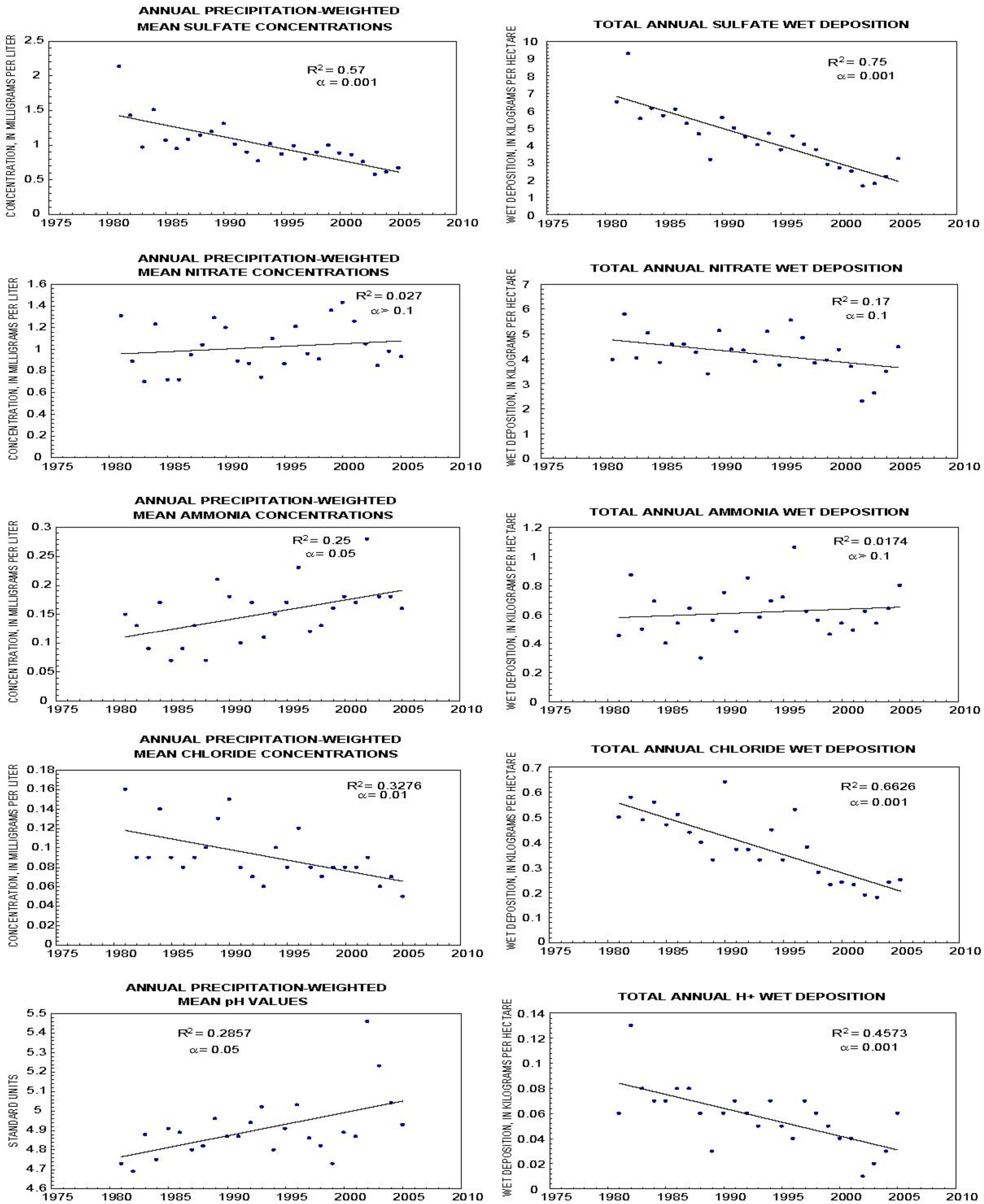


Figure 3. Annual concentrations and wet deposition of selected constituents at Mesa Verde National Park, 1981-2006. Data are from the National Atmospheric Deposition Program. Significance (α) from Mann-Kendall trend test.

Visibility

I. Background

Title 42 U.S.C. §§ 7491 and 7492 of the Clean Air Act established a national policy to study and protect visibility in Federal class I areas. It declares as a national goal "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution."[1] Of several mandatory class I areas Federal areas on the Colorado Plateau, Arches National Park, Canyonlands National Park, the Weminuche Wilderness, and Mesa Verde National Park lie within near or immediate proximity to the Four Corners Region.

Several planning and monitoring authorities have evolved from this statutory requirement, two of which are able to directly address visibility concerns in the Four Corners region. The Interagency Monitoring of Protected Visual Environments (IMPROVE) program was initiated in 1985, and has implemented an extensive long term monitoring program in the National Parks and Wilderness Areas.[2] Additionally, the Western Regional Air Partnership (WRAP) was formed in 1997 as the successor to the Grand Canyon Visibility Transport Commission, and promotes the implementation of recommendations that were made in the previous commission.[3] Specifically, the WRAP partnership is implementing a regional planning process to improve visibility in all western Class I areas "by providing the technical and policy tools needed by states and tribes to implement the federal regional haze rule."[4]

EPA issued the final Regional Haze Rule on April 22, 1999.[5] "The rule requires the states, in coordination with the Environmental Protection Agency, the National Park Service, U.S. Fish and Wildlife Service, the U.S. Forest Service, and other interested parties, to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment."[6] This regulation is also anticipated to have the additional benefits of improving visibility outside of class I areas, as well as ameliorating the health impacts associated with fine particulates (PM 2.5).[7]

II. What affects visibility and how is it monitored?

The interaction between certain gasses, particulate matter, and the light that passes through the atmosphere yields the basic processes through which visibility is affected. Gasses and *aerosols* may scatter or block sunlight through *diffraction, absorption,* and *refraction*. When sunlight encounters gasses and aerosols, it scatters preferentially as a function of the size of the particles that it encounters.[8] The relationship between particulate size and light is extremely important, as it ultimately accounts for changes in color and *haze*. Although the total mass of coarse particles (PM 10) in the atmosphere outnumbers the total mass of fine particles (PM 2.5), the finer particles "are the most responsible for scattering light" because they scatter light more efficiently, and because there are more of them.[9] Consequently, the origin and transport of fine particles (PM 2.5) is of greatest concern when assessing visibility impacts.[10]

In the most general sense, visibility is the effect that various aerosol and lighting conditions have on the appearance of landscape features.[11] While photography is the simplest method used to convey visibility impairment, it is difficult to garner quantitative information from photographs, digital pictures, or slides. Because some direct measurement of the atmosphere's optical qualities is desired, most visibility programs include a measure of either atmospheric *extinction* or *scattering*.

> The *scattering coefficient* is a measure of the ability of particles to scatter photons out of a beam of light, while the *absorption coefficient* is a measure of how many photons are absorbed. Each parameter is expressed as a number proportional to the amount of photons scattered or absorbed per distance. The sum of scattering and absorption is referred to as *extinction* or attenuation.[12] (Emphasis added.)

Extinction is measured by devices such as the *transmissometer* and *nephelometer*. Most monitoring programs use combinations of these devices to measure extinction and scattering. Extinction is usually described in terms of *inverse megameters* (Mm^{-1}), and is proportional to the amount of light that is lost as it travels over a million meters.[13] *Deciviews* is another measurement of extinction, but which is scaled in a way that it is perceptually correct. "For example, a one deciview change on a 20 deciview day will be perceived to be the same as on a 5 deciview day."[14] Because deciviews are *scaled* so that they may describe *changes* in visibility, they must be distinguished from extinction as it can otherwise be described in inverse megameters and *visual range*.

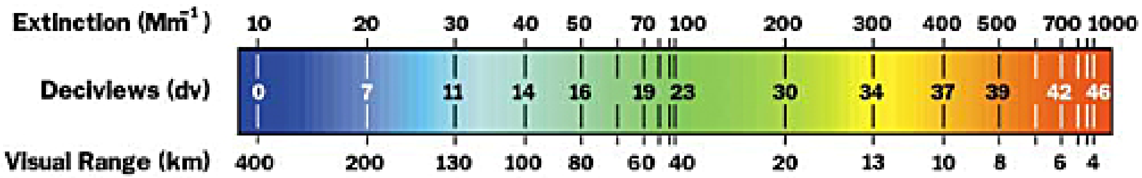


Fig. A Comparison of extinction (Mm^{-1}), deciview (dv), and visual range (km).
(Source: Malm, William C. Introduction to Visibility.)

In addition to the measurements of scattering and extinction, it is also helpful to know what materials in the air are contributing to visibility impairment. *Particle measurements* are normally made in conjunction with optical measurements "to help infer the cause of visibility impairment, and to estimate the source of visibility reducing aerosols."[15] The size and composition of particles are the most commonly identified characteristics that are used in visibility monitoring programs. Additionally, "particles between 0.1 to 1.0 microns are most effective on a per mass basis in reducing visibility and tend to be associated with man-made emissions."[16] These fine particles are usually grouped under the category PM 2.5, which refers to particles that are less than 2.5 microns large. (As discussed earlier, PM 2.5 particles are in general the most effective in scattering light due to their small size.) "The IMPROVE fine particle modules employ a cyclone at the air inlet which spins the air within a chamber. Fine particles are lifted into the air stream where they are siphoned off and collected on a filter substrate for alter analysis."[17] Once the size of particles has been measured, they are speciated by composition. The identification of sulfates, nitrates, organic material, elemental carbon (soot) and soil "helps determine the chemical-optical characteristics and the ability of the particle to absorb water (RH effects) and is important to separate out the origin of the aerosol."[18]

> A visibility impairment value is calculated for each sample day. To get a valid measurement, all four modules must collect valid samples. The regional haze regulations use the average visibility values for the clearest days and the worst days. The worst days are defined as those with the upper 20% of impairment values for the year, and the clearest days as the lowest 20%. The goal is to reduce the impairment of the worst days and to maintain or reduce it on the clear days.[19]

For data to be considered under the regional haze regulations, it must meet the minimum criteria for the number of daily samples needed in a valid year: 1.) 75% of the possible samples for the year must be complete; 2.) 50% of the possible samples for each quarter must be complete; 3.) No more than 10 consecutive sampling periods may be missing.[20]

As noted above, the filter analysis provides the concentrations and composition of atmospheric particles. The *source contribution* to visibility impairment can be indicated from the analysis of trace elements:

vanadium/nickel	»	petroleum-based facilities, autos
arsenic	»	copper smelters
selenium	»	power plants
crustal elements	»	soil dust (local, Saharan, Asian)
potassium (nonsoil)	»	forest fires[21]

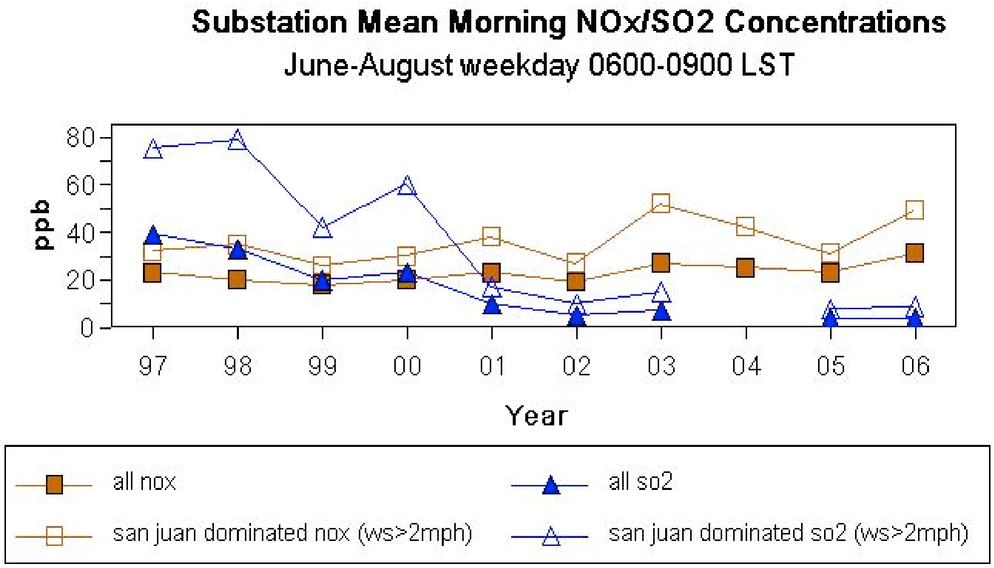
III. Visibility in the Four Corners

Currently, there are four sites within the Four Corners region that monitor visibility: Mesa Verde National Park, the Weminuche Wilderness (near Purgatory,) the Shamrock Mine (southeast La Plata County,) and Canyonlands National Park. Of these four sites, only the Forest Service monitoring station at the Shamrock Mine records images, and is included in IMPROVE's optical and scene monitoring network. Additionally, because the Canyonlands site lies on the margin of the Four Corners Region, and it is also located at a comparatively lower elevation north of the Blue Mountains, it may not serve as the best indicator of visibility trends in the Four Corners proper.

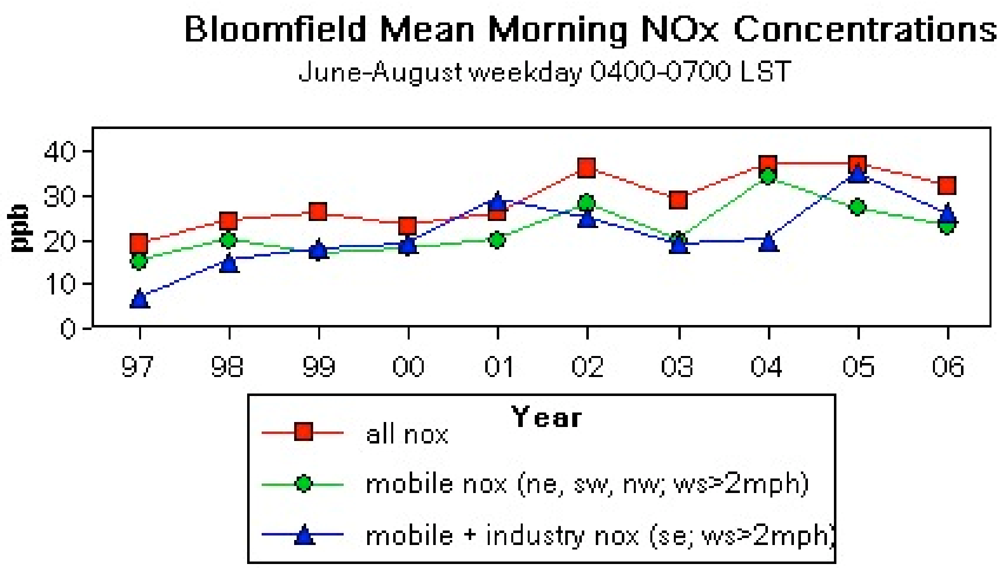
Preliminary analysis of deciview trends at Mesa Verde, and also of visibility-impairing gasses and particulates as monitored at other sites, does not reveal a clear trend of how visibility might be changing in the Four Corners. This appraisal is not concomitant with the observations of many area residents. It may be indicative of monitoring gaps that exist in the Four Corners, and it has led to the perception by members of the Task Force Monitoring Group that a comprehensive, detailed analysis of all available data regarding visibility is greatly needed.

Despite that ambiguity, however, there are a few details worth noting. In September of 2005, the Interim Emissions Workgroup of the Four Corners Air Quality Task Force recommended that an ambient monitoring program for gaseous ammonia be initiated in the Four Corners region. The purpose of this program is to set a current baseline of ambient gaseous ammonia concentrations in the Four Corners, that can be compared to monitored values in approximately 3-5 years after the implementation of NOx controls (e.g. NSCR) on oil and gas equipment. The use of NSCR may increase ammonia emissions in the area, but these emissions have not been quantified and may or may not significantly affect visibility. Ammonia at high enough concentrations can contribute to worsening visibility by forming PM 2.5 ammonium nitrates and ammonium sulfates.

Additionally, the implementation of new SO_2 controls at the San Juan Generating Station in 1999 has successfully reduced SO_2 emissions in the area. Because of the high impact that SO_2 can have upon visibility, that reduction has likely made a positive impact upon visibility conditions in the Four Corners. However, changes in monitoring conditions at San Juan Substation have not been limited to a decrease in SO_2. Concurrently, it appears that NOx concentrations have risen, and now dominate over SO_2:



For the same time period, similar increases in NOx have been observed in Bloomfield, and it appears that NOx may be slowly increasing as a regional trend:



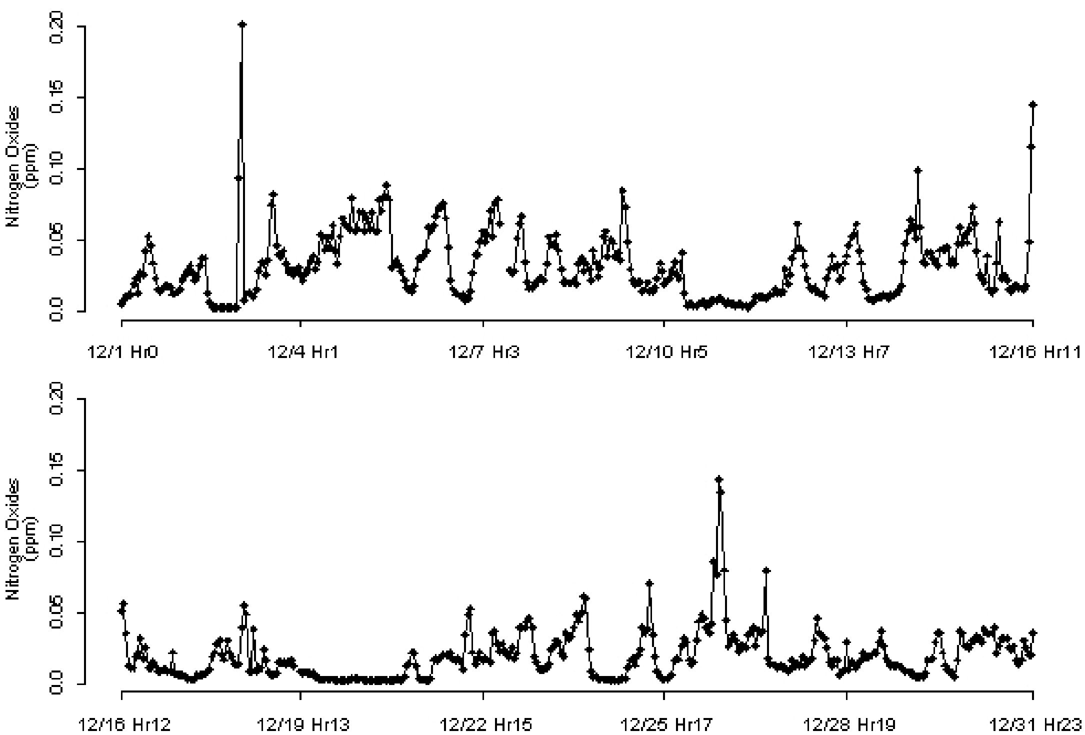
Many citizen's accounts on deteriorating visibility in the Four Corners have centered upon wintertime episodes. The ways in which seasonal differences may impact visibility is very important. In the summertime, the "confining layer" of the atmosphere, which generally holds pollutants below a certain altitude, is much higher. Additionally, the extra heat associated with warmer seasons allows the atmosphere to move and mix more readily. The result is that, in the summertime, visibility-impairing pollutants can mix more easily, and dilute within in a greater vertical distance. Conversely, in the wintertime, that confining layer is usually much lower (thus the prevalence of wintertime inversions.) In colder seasons, the atmosphere does not move or mix as easily. Therefore, generally, wintertime pollutants are held closer to the ground level, and they cannot readily dilute into the upper atmosphere. Given this effect, the same level of regional emissions year-round will likely be more noticeable in the winter as *layered haze*. The addition of rising emissions levels will compound this effect in the wintertime.

Wintertime haze near Kline, Colorado. 12/05/2006. *See also*: A Resident's Observation of Visibility, this section.

Excellent visibility, photo taken one mile west of previous photo. 10/21/2006.

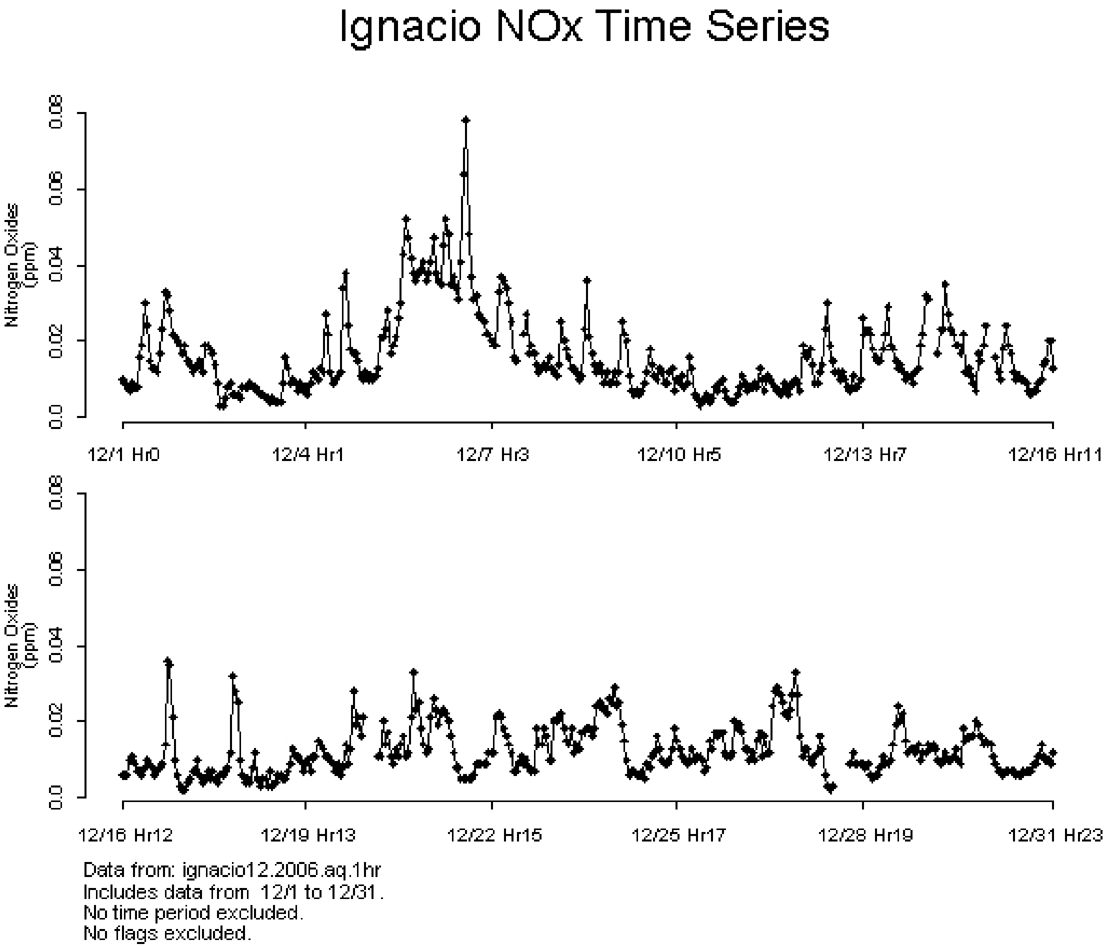
The considerations outlined above reasonably lead to the hypothesis that citizens' accounts of deteriorating visibility, as they are specific to wintertime episodes, may be partially caused by increasing NOx emissions. For an initial test of this hypothesis, we may review what NOx concentrations existed in the region at the time of the 12/05/2006 photograph:

Substation NOx time series

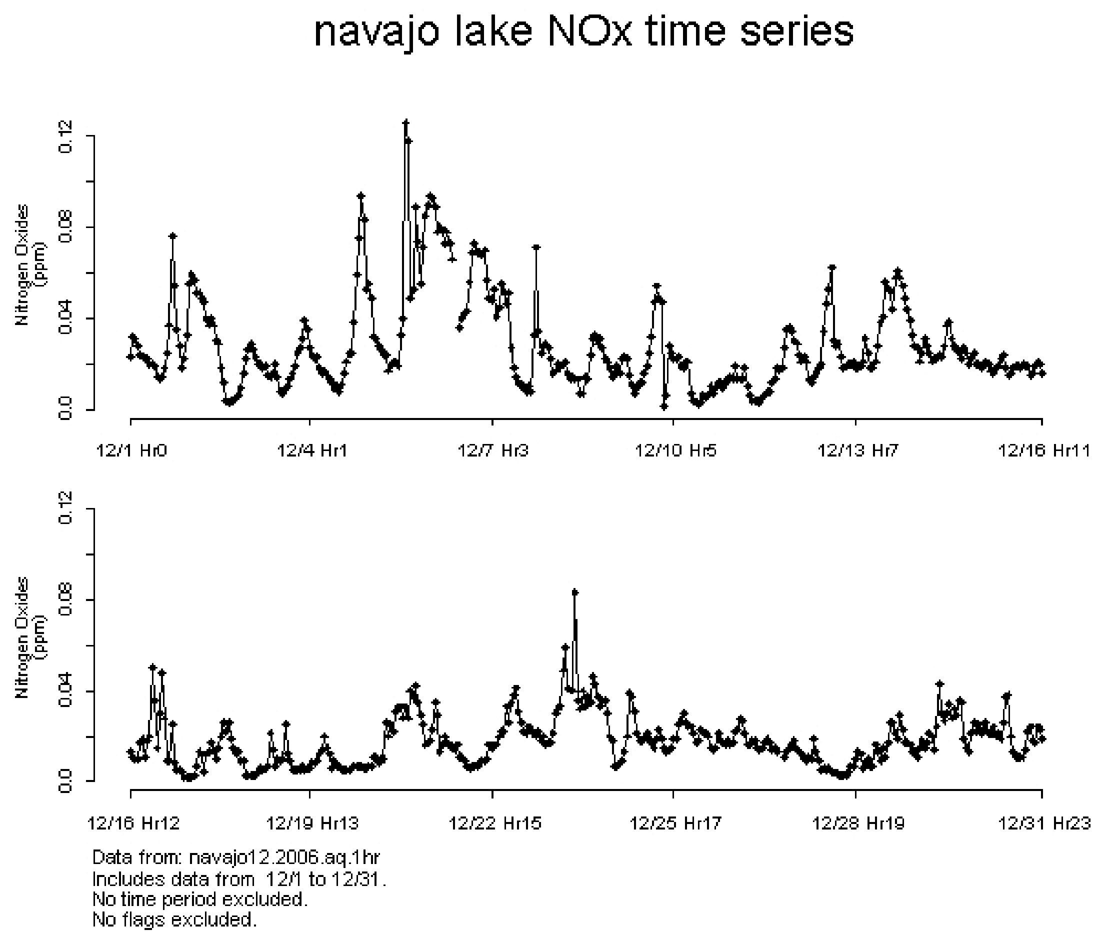


Data from: substation12.2006.aq.1hr
Includes data from 12/1 to 12/31.
No time period excluded.
No flags excluded.

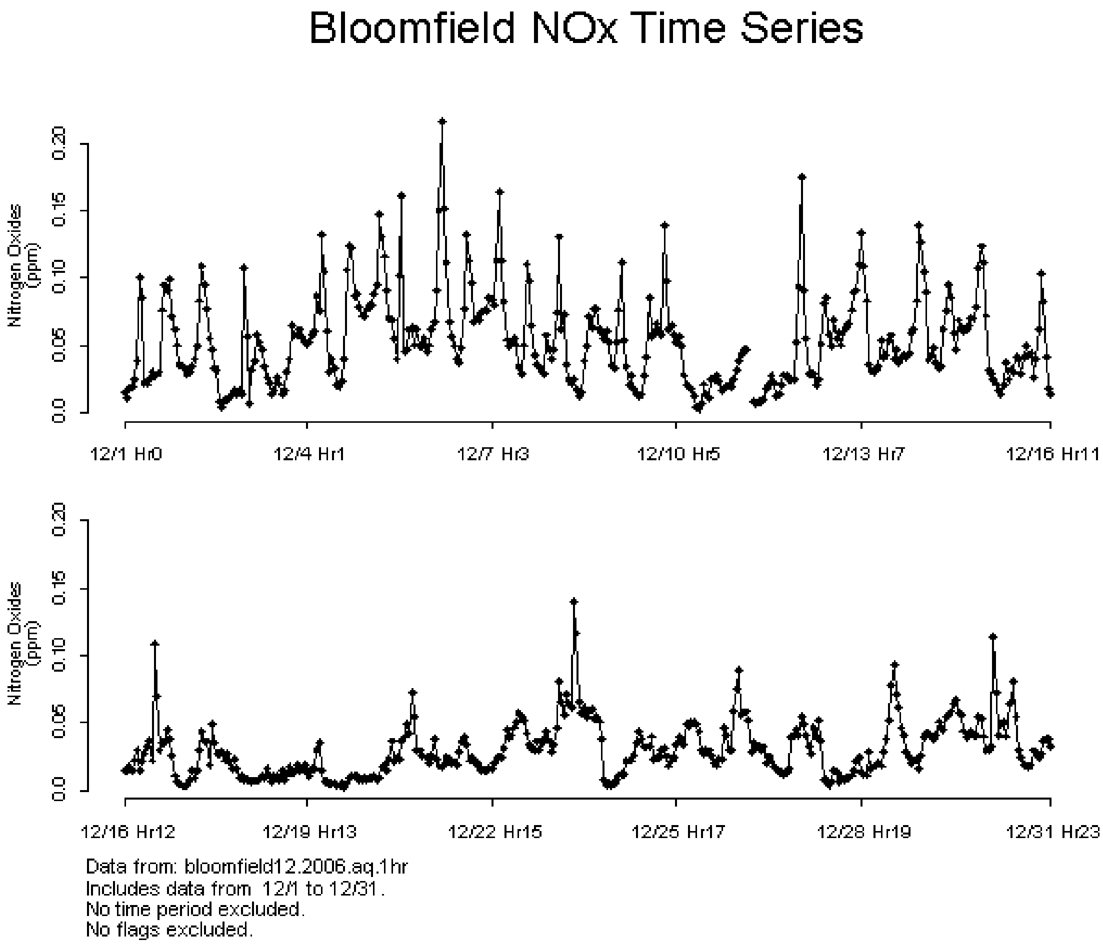
Elevated NOx concentrations existed at the San Juan Substation, with the most pronounced event occurring approximately 48 hours before the 12/05/2006 photograph.



Elevated NOx concentrations existed at the Ignacio monitoring site approximately 24 hours after the 12/05/2006 photograph.



Elevated NOx concentrations existed at the Navajo Lake monitoring site, with the most pronounced concentrations occurring on 12/05/2006.



Elevated NOx concentrations existed at the Bloomfield monitoring site, with the most pronounced concentrations occurring within 24 hours of the 12/05/2006 photograph.

It appears that NOx concentrations were a contributing factor behind the visibility impairment episode documented in the 12/05/2006 photograph. These preliminary observations raise a number of additional considerations. First, there exists a great value in the photographic documentation of visibility. These elevated NOx concentrations might not have been considered if one were to only examine particulate data over a given time period. *Visual observations*, although subjective, provide the first clue that will lead the inquisitor to examine specific episodes and time periods. The contemplation of criteria such as color, location, and the *expanse* of impairment episodes considers the *regional nature* of visibility impairment in a way that no site-specific particulate measurement can do. In a sense, visual accounts and photographic documentation is a *top-down* approach that reveals what data needs to be specifically considered, and where additional monitoring would be useful.

Second, in the case of indeterminate deciview trends at Mesa Verde, the preceding discussion on photographic documentation obliges us to consider the monitoring site's location. Mesa Verde is situated upon the uppermost reaches of the *Four Corners Platform*. This geologic plateau rises above the valleys and basins of the Four Corners region, and typifies the area's rugged and varied topography. The monitoring site at Mesa Verde is located at roughly 7,200 feet above sea level, while most emissions in the region occur in the San Juan Basin to the south, at roughly 5,000 feet. (Likewise, most other emissions in the region are related to human activity, and occur in the other multiple valleys and basins that are topographically separated from the Park.) Given the occurrence of wintertime inversions and a lower confining atmospheric layer, it is entirely possible that what is observed as severe visibility impairment will not be recorded at Mesa Verde, because the monitoring site will be *above the confining layer*. The absence of photographic documentation coexistent with particulate measurements in the Park causes that data to be extrapolated from air quality within the Park itself, and it will not effectively consider what an observer might actually see as she looks across the region from that location.

It is reasonable to assume that (wintertime) visibility impairment in the Four Corners is exacerbated by the area's rugged topography, which often confines visibility impairment to within the region's numerous basins and deep valleys. Additionally, that visibility monitoring in the Four Corners which is reliant on particulate measurements is located at higher elevations, and is not likely to record events related to low confining layers and atmospheric inversions. (I.e. Mesa Verde and the Weminuche.) These locations are, however, great *vantage points* from which visibility may be observed, but they forgo this opportunity because they do not include photographic documentation. Furthermore, Canyonlands National Park is not a good location to observe visibility as it relates to the Four Corners, because it is too distant from the region. (Both the path of emissions transport and line of sight from the Four Corners to Canyonlands is blocked by the higher elevations surrounding the Blue Mountains and Bear's Ears.) That leaves only one site—the Shamrock Mine—from which visibility in the Four Corners Region can be satisfactorily observed and documented year-round.

IV. Suggestions for Future Monitoring Work

Air quality monitoring is a rather expensive operation, and so resources that might provide for saturation studies or additional permanent monitoring should be allocated in consideration of monitoring goals as a whole. However, it is still reasonable to advocate some additional monitoring of visibility, as most of the following suggestions could be incorporated into existing sites.

Last, most visibility monitoring in the Four Corners is unevenly distributed (or restricted) to Class I areas. Therefore, visibility monitoring within these Class I areas is not conducive of a regional trends assessment, especially because they are based on a very few site-specific particulate measurements. Furthermore, the regional monitoring of visibility is desirable, because it can assist with the protection of Class I areas and EPA's regional haze rule. Additionally, regional monitoring of visibility will better address the value that citizens place upon the vistas that exist outside of Class I areas, while recognizing how visibility impacts citizens' perceptions of air quality as a whole. In sum, it is highly desirable that we consider how visibility monitoring in the Four Corners region can be perfected, with the intent of making a *strong regional assessment*.

1. It is suggested that the monitoring sites at Mesa Verde and in the Weminuche resume photographic documentation.

2. Many previous studies of visibility in the Four Corners relate only to site-specific locations, and often conflict in their findings. A comprehensive assessment of historical data is needed, in order to determine regional trends or changes in visibility. Currently, it is very difficult not only to establish regional trend analyses, but also to compare them to historical baseline data.

3. Additional visibility monitoring should be established at locations in the region other than what exists in Class I areas. This additional monitoring:

1. could be incorporated into existing monitoring sites;
2. should include photographic documentation;
3. and, it should specifically consider how topographical variations impact the measurement of visibility.

4. The apparent contribution of NOx emissions to wintertime visibility impairment is recommended for further study.

V. Works Cited:

1. 42 U.S.C. § 7491 (a)(1).
2. http://vista.cira.colostate.edu/improve/ (access date 4/05/2007).
3. http://www.wrapair.org/facts/index.html (access date 4/05/2007).
4. Id.
5. http://vista.cira.colostate.edu/improve/Overview/hazeRegsOverview_files/v3_document.htm (access date 4/05/2007). *See also* http://www.epa.gov/air/visibility/program.html.

6. http://www.epa.gov/air/visibility/program.html (access date 4/05/2007).
7. http://vista.cira.colostate.edu/improve/Overview/hazeRegsOverview_files/v3_document.htm
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10. Id. at 9.
11. Id.
12. Id. at 27.
13. Id.
14. Id. at 35.
15. Id.
16. Id. at 28.
17. Id. at 28, 29.
18. IMPROVE 2007 Calendar.
19. Malm at 29.
20. IMPROVE 2007 Calendar.
21. Id.
22. Id.

The complete photographic record prepared by Erich Fowler is available by contacting Mark Jones at mark.jones@state.nm.us. This is a very large file (over 100 MB).

Mitigation Option: Interim Emissions Recommendations for Ammonia Monitoring

I. Description of the mitigation option

The following mitigation option paper is one of three that were written based on interim recommendations that were developed prior to the convening of the Four Corners Air Quality Task Force. Since the Task Force's work would take 18-24 months to finalize, and during this time oil and gas development could occur at a rapid pace, an Interim Emissions Workgroup made up of state and federal air quality representatives was formed to develop recommendations for emissions control options associated with oil and gas production and transportation. The Task Force includes these recommendations as part of its comprehensive list of mitigation options.

Implement an ambient monitoring program for ammonia

C. Assess importance of ammonia to visibility
D. Visibility modeling would be more accurate if ammonia data were available
E. Ammonia emission impacts from NSCR can be better evaluated
F. US EPA Region 6 will assist with this effort

Evaluate data on ammonia emissions from engines less than 300 HP equipped with NSCR

- Testing should be done in the field
- Funding would need to be secured
- A contractor to make measurements would need to be found

II. Description of how to implement

The ambient monitoring program for ammonia would be conducted under the auspices of EPA Region 6. The appropriate agencies to implement this are EPA Region 6 and the New Mexico and Colorado departments of environmental quality. Collecting data on ammonia emissions from engines less than 300 HP would be voluntary and funding would need to be secured.

III. Feasibility of the Option

The technical feasibility of the ambient monitoring has already demonstrated. Specifically, the technical feasibility of measuring ammonia emissions from engines with NSCR has been demonstrated as part of a research project initially started by Colorado State University. However the exact methodology is not yet chosen. The environmental feasibility is negligible since only samples are collected. The economic feasibility depends on finding someone to pay for the sampling program

IV. Background data and assumptions used

The ambient monitoring would be conducted either by collecting samples or by real time analysis depending on equipment selected. Approximate measurements can be made using sampling tubes similar to Draeger tubes. The assumption is that a baseline ammonia level should be established and that potential increases may be observed because of the use of large numbers of rich burn engines with NSCR catalysts.

This methodology is already being tested in the Colorado State University research project.

V. Any uncertainty associated with the option

The cost of the ambient monitoring program is not well established because the monitoring technology is not fully specified. Therefore, there is some uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option

To be determined.

VII. Cross-over issues to the other source groups

This mitigation option would cross over to the Oil and Gas work group.

RESOLUTIONS

Introduction

In January, 2005 the Cortez/Montezuma League of Women Voters Air Quality Committee began its study of air quality issues in Montezuma County. It became evident that to study air quality we needed facts. To gain facts we needed monitoring. A committee was formed consisting of the following League of Women Voters members: Sylvia Olivia-air quality consultant, Judy Schuenemeyer-lawyer, Eric Janes-water quality expert, Jack Schuenemeyer-statistician, Mary Lou Asbury-spokesperson. The committee met frequently and came up with a plan of action.

We invited Mark Larson, our state representative and Jim Isgar, our state senator, to a League of Women Voters meeting. Sylvia showed the plume model (a computer model of the plume movement from the areas existing power plants and the proposed 2 new power plants). We discussed the need for monitoring in the Montezuma Valley. Both agreed to take our concerns to the Colorado Legislature and the Colorado Health Department. The ground work was laid.

The committee then met in Durango with the Congressional staff of Senator Ken Salazar and Representative John Salazar. To show governmental and community support for air monitoring we decided we needed to take resolutions to the Montezuma County Commissioners, Cortez City Council, and Mancos and Dolores Town Boards. A power point presentation with facts on ozone and mercury was decided upon.

The committee met over a period of 2-3 months to put the finishing touches on the power point, commentary and resolutions. Presentations were scheduled starting in June,2005.

Sylvia Olivia, Eric Janes, Judy and Jack Scheunemeyer and Mary Lou Asbury were in attendance for all presentations. Questions were answered to the satisfaction of all. Resolutions were signed in support of getting air monitoring, data collection and analysis from the EPA, BLM-CO, BLM-NM, and USGS. These have been mailed to all interested parties including all the Colorado Congressional Delegation and to our state representative and senator. The need was recognized, but the funding has been problematic.

The committee has continued to do presentations to various groups to gain support for the need for air monitoring in the Montezuma Valley. The need becomes more critical as final plans are being made to construct a new power plant. Also, more coal bed methane wells are proposed in the San Juan Basin and throughout the Four Corners Region.

There are many health issues and lifestyle concerns which require an air quality monitoring system. The League of Women Voters resolutions help show concern from representative government. The resolutions follow from the Montezuma County Commissioners, Cortez City Council, Mancos Town Board and Dolores Town Board.

City of Cortez
Resolution No. 17, Series 2005
United States Environmental Protection Agency

Whereas, the City Council of the City of Cortez, Montezuma County, Colorado is interested in a healthy environment and clean air for citizens of the City, and

Whereas, concerns are being raised by City residents about the possible effects on the City environment and air quality by the proposed Desert Rock Energy Project to be built on Navajo Nation lands in the State of New Mexico, and

Whereas, Sithe Global Power, Inc. of Houston Texas and the Dine Power Authority have begun planning for two 750 MW coal-fired electric generating units and associated facilities for the proposed plant, and

Whereas, the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution, such as that emitted from the San Juan and Four Corners electric generation plants in New Mexico, greatly exceeds that emitted from all sources in the County, and

Whereas, mercury is a known pollutant emitted from coal-fired electric power generating plants and recent studies have shown that mercury can cause neurological damage and is especially harmful to developing fetuses and children, and

Whereas, the second highest concentrations of mercury in rain and snow recorded for any location in the western United States for the past two years have been found in Mesa Verde National Park, and

Whereas, State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury, and

Whereas, City residents with respiratory problems such as asthma are experiencing additional health problems on days when air pollution appears to be higher, and

Whereas, Mesa Verde National Park is the only known site for air quality data collection in Montezuma County and may not adequately provide a basis for characterizing air for the remainder of the County, including the City of Cortez, and

Whereas, additional monitoring sites are needed in the County to measure current levels of air pollution in order to assess the additional impact on air quality of the proposed power plant.

Now Therefore Be It Resolved by the Cortez City Council,

That, the Council finds that additional air quality monitoring sites are needed elsewhere in Montezuma County to adequately assess the impact of air pollution from sources outside the State of Colorado on the health of City residents, and

Further that, the Council requests that the Regional Administrator of the United States Environmental Protection Agency, Denver seek funding in its Fiscal Year 2006 and 2007 budgets for air and water monitoring equipment to be placed at sites through Montezuma County. We ask that funding be directed to an entity in southwestern Colorado mutually agreeable to the Montezuma County Commissioners, the EPA, and other parties as they shall deem appropriate to query.

MOVED, SECONDED AND ADOPTED THIS 14th DAY OF JUNE 2005.

Orly Lucero, Mayor

ATTEST:

Linda L. Smith, City Clerk

City of Cortez
Resolution No. 14, Series 2005
USGS Colorado Water Science

Whereas, the City Council of the City of Cortez, Montezuma County, Colorado is interested in a healthy environment and clean air for citizens of the City, and

Whereas, concerns are being raised by City residents about the possible effects on the City environment and air quality by the proposed Desert Rock Energy Project to be built on Navajo Nation lands in the State of New Mexico, and

Whereas, Sithe Global Power, Inc. of Houston Texas and the Dine Power Authority have begun planning for two 750 MW coal-fired electric generating units and associated facilities for the proposed plant, and

Whereas, the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution, such as that emitted from the San Juan and Four Corners electric generation plants in New Mexico, greatly exceeds that emitted from all sources in the County, and

Whereas, mercury is a known pollutant emitted from coal-fired electric power generating plants and recent studies have shown that mercury can cause neurological damage and is especially harmful to developing fetuses and children, and

Whereas, the second highest concentrations of mercury in rain and snow recorded for any location in the western United States for the past two years have been found in Mesa Verde National Park, and

Whereas, State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury, and

Whereas, City residents with respiratory problems such as asthma are experiencing additional health problems on days when air pollution appears to be higher, and

Whereas, Mesa Verde National Park is the only known site for air quality data collection in Montezuma County and may not adequately provide a basis for characterizing air for the remainder of the County, including the City of Cortez, and

Whereas, additional water monitoring sites on a bi-weekly to monthly frequency are needed on the Dolores River and Mancos River systems in the County to measure levels of mercury in order to assess the ultimate fate of mercury from the proposed power plant and existing power plants.

Now Therefore Be It Resolved by the Cortez City Council,

That, the Council finds that additional water monitoring sites for mercury are needed on the Dolores and Mancos River systems to adequately assess the ultimate fate of mercury from air pollution sources outside the State of Colorado on the health of City residents, and

Further that, the Council requests that the USGS Colorado Water Science Director in Denver seek funding in the Fiscal Year 2006-2007 budgets for increasing the USGS Colorado ability to monitor mercury in water in the Dolores and Mancos River systems.

MOVED, SECONDED AND ADOPTED THIS 14th DAY OF JUNE 2005.

Orly Lucero, Mayor

ATTEST:

Linda L. Smith, City Clerk

RESOLUTION # 230
TOWN OF DOLORES
SUPPORT FOR AIR AND WATER MONITORING FUNDING THROUGH
COLORADO BUREAU OF LAND MANAGEMENT

WHEREAS, The Town of Dolores Board of Trustees, Montezuma County, Colorado is interested in a healthy environment and clean air for citizens of the Town; and

WHEREAS, concerns are being raised by Town residents about the possible effects on the Town environment and air quality by the proposed Desert Rock Energy Project to be built on Navajo Nation lands in the State of New Mexico; and

WHEREAS, Sithe Global Power, Inc. of Houston, Texas and the Dine' Power Authority have begun planning for two 750 MW coal-fired electric generating units and associated facilities for the proposed plant; and

WHEREAS, the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution, such as that emitted from the San Juan and Four Corners electric generation plants in New Mexico, greatly exceeds that emitted from all sources in the County; and

WHEREAS, mercury is a known pollutant emitted from coal-fired electric power generating plants and recent studies have shown that mercury can cause neurological damage and is especially harmful to developing fetuses and children; and

WHEREAS, the second highest concentrations of mercury in rain and snow recorded for any location in the western United States for the past two years have been found in Mesa Verde National Park; and

WHEREAS, State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury; and

WHEREAS, County residents with respiratory problems such as asthma are experiencing additional health problems on days when air pollution appears to be higher; and

WHEREAS, Mesa Verde National Park is the only known site for air quality data collection in Montezuma County and may not adequately provide a basis for characterizing air for the remainder of the County, including the Town of Dolores; and

WHEREAS, additional monitoring sites are needed in the County to measure current levels of ozone, mercury in rain and snow, and Dolores and Mancos River mercury concentrations in order to assess the additional impact on air quality of the proposed power plant, and

NOW, THEREFORE BE IT RESOLVED, that the Town Board, Town of Dolores finds that additional air and water monitoring sites are needed elsewhere in Montezuma County to adequately assess the impact of air pollution from sources outside the State of Colorado on the health of Town residents; and

BE IT FURTHER RESOLVED, that the Town Board, Town of Dolores requests that the Colorado Bureau of Land Management see funding in its Fiscal Year 2006 and 2007 budgets for air and water monitoring equipment to be placed at sites throughout Montezuma County. The Town Board asks that funding be directed to an entity in southwestern Colorado mutually agreeable to the Dolores Town Board, the Colorado Bureau of Land Management, and other parties as they shall deem appropriate to query.

Done this 12th day of September, 2005

Marianne Mate, Mayor
Town Board of Trustees

ATTEST:

Ronda Lancaster

Ronda Lancaster,
Town Clerk/Administrator

SEAL

1900

RESOLUTION NO. 2006–40

A RESOLUTION OF THE BOARD OF COUNTY COMMISSIONERS OF LA PLATA COUNTY, COLORADO, FOR REGION IX AIR DIVISION OF THE ENVIRONMENTAL PROTECTION AGENCY CONCERNING THE CLEAN AIR ACT PERMIT FOR THE DESERT ROCK POWER PLANT

WHEREAS, the United States Environmental Protection Agency (US EPA) Region IX has proposed a Clean Air Act permit that would authorize construction of a 1500-megawatt coal-fired power plant on the Navajo Nation; and

WHEREAS, the permit regulates the reduction of particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, volatile organic compounds, and lead emissions with the Best Available Control Technology, and must comply with health-based National Ambient Air Quality Standards; and

WHEREAS, Chapter 6, page 6.1 of the La Plata County Comprehensive Plan - Environmental Resources states "La Plata County's natural resources are a valuable community asset. Ensuring their preservation and appropriate use is important to both the natural beauty and economy of La Plata County;" and

WHEREAS, "Environmental Quality and unique natural features are what defines the character of La Plata County and ensuring their continued viability and health is important;" and

WHEREAS, the comment period for this clean air quality permit closes before the draft Environmental Impact Statement is released to the public resulting in an incomplete understanding of the cumulative impacts of the plant; and

WHEREAS, mercury is a significant and demonstrable problem resulting in a degradation in the quality of life for La Plata County citizens, failure to include the monitoring of mercury, a byproduct of all coal burning power plants would be negligent to the citizens;

NOW THEREFORE, BE IT RESOLVED BY THE BOARD OF COUNTY COMMISSIONERS OF LA PLATA COUNTY, COLORADO, AS FOLLOWS:

1. That the La Plata County Board of County Commissioners hereby requests that the Environmental Protection Agency Region IX Air Division deny the Clean Air Act Permit for Desert Rock Power Plant so the full Environmental Impact Statement for this project is completed to allow the citizens of La Plata County an understanding of the full cumulative impacts from the proposed plant.

2. That the La Plata County Board of County Commissioners hereby requests that all available technology be utilized to reduce the amount of pollutants, including mercury, emitted by this plant.

DONE AND ADOPTED IN DURANGO, LA PLATA COUNTY, COLORADO, this 24th day of October, 2006.

BOARD OF COUNTY COMMISSIONERS
LA PLATA COUNTY, COLORADO

ATTEST

____
Wallace "Wally" White, Chair

____
Clerk to the Board

____
Robert A. Lieb, Vice Chair

____
Sheryl D. Ayers, Commissioner

DISTRIBUTION: United States Environmental Protection Agency Region IX
Attn: Robert Baker
75 Hawthorne Street
San Francisco, CA 94105
desertrockairpermit@epa.gov

Resolution (BLM-NM)

Whereas the Board of Trustees, Town of Mancos, Montezuma County, Colorado is interested in a healthy environment and clean air for citizens of the Town, and

Whereas concerns are being raised by Town residents about the possible effects on the Town environment and air quality by the proposed Desert Rock Energy Project to be built on Navajo Nation lands in the State of New Mexico, and

Whereas Sithe Global Power, Inc. of Houston Texas and the Dine Power Authority have begun planning for two 750 MW coal-fired electric generating units and associated facilities for the proposed plant, and

Whereas the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution, such as that emitted from the San Juan and Four Corners electric generation plants in New Mexico, greatly exceeds that emitted from all sources in the County, and

Whereas mercury is a known pollutant emitted from coal-fired electric power generating plants and recent studies have shown that mercury can cause neurological damage and is especially harmful to developing fetuses and children, and

Whereas the second highest concentrations of mercury in rain and snow recorded for any location in the western United States for the past two years have been found in Mesa Verde National Park, and

Whereas State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury, and

Whereas County residents with respiratory problems such as asthma are experiencing additional health problems on days when air pollution appears to be higher, and

Whereas Mesa Verde National Park is the only known site for air quality data collection in Montezuma County and may not adequately provide a basis for characterizing air for the remainder of the County, including the Town of Mancos, and

Whereas additional monitoring sites are needed in the County to measure current levels of ozone, mercury in rain and snow, and Dolores and Mancos River mercury concentrations in order to assess the additional impact on air quality of the proposed power plant, Now Therefore

Be It Resolved, that the Board of Trustees, Town of Mancos finds that additional air and water monitoring sites are needed elsewhere in Montezuma County to adequately assess the impact of air pollution from sources outside the State of Colorado on the health of Town residents, and

Be It Further Resolved, that the Board of Trustees, Town of Mancos requests that the Bureau of Land Management New Mexico State Director, Santa Fe seek funding in the Fiscal Year 2006-2007 budgets for air quality monitoring equipment for ozone to be placed at appropriate sites in Montezuma County. We ask that funding be directed to an entity in southwestern Colorado mutually agreeable to the Board of Trustees, the BLM New Mexico and Colorado State Directors, and to other parties as they shall deem appropriate.

APPROVED THIS 22 DAY of June, 2005

Greg Rath

Greg Rath, Mayor

Michele Black

Michele Black, Mayor Pro-Tem

Perry Lewis

Herman J. Muniz

Herman Muniz

Nick Baumgartner

Nick Baumgartner

Ray Martinez

Ray Martinez

Nicki Elmore

Nicki Elmore

THE BOARD OF COUNTY COMMISSIONERS
OF THE COUNTY OF MONTEZUMA
STATE OF COLORADO

At a regular meeting of the Board of County Commissioners of Montezuma County, Colorado, duly convened and held the 13th day of June, 2005, with the following persons in attendance:

Commissioners:	Dewayne Findley, Gerald Koppenhafer, and Larrie Rule
Commissioners Absent:	
County Administrator:	Thomas J. Weaver
County Attorney:	Bob Slough
Clerk and Recorder:	Carol Tullis

the following proceedings, among others, were taken:

Resolution # 5-2005

Resolution (EPA)

WHEREAS, the Commissioners of Montezuma County Colorado are interested in a healthy environment, clean air and water for citizens of Montezuma County; and

WHEREAS, concerns are being raised by Montezuma County residents about the possible effects on air quality and water by the proposed Desert Rock Energy Project; and

WHEREAS, the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution; and

WHEREAS, mercury is a known pollutant emitted from coal-fired electric power generating plants; and

WHEREAS, State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury; and

WHEREAS, Mesa Verde National Park is the only known site for air quality data collection in Montezuma County; and

WHEREAS, additional monitoring sites may be needed in the County to measure current levels of ozone, and mercury in order to assess the additional impact of the proposed power plant; and

WHEREAS, the Commissioners of Montezuma County find that additional air and water monitoring sites may be needed elsewhere in the County to adequately assess the impact of air pollution and water contamination,

NOW THEREFORE BE IT RESOLVED THAT the Commissioners request that the Regional Administrator of the United States Environmental Protection Agency, Denver seek funding for equipment, operation and data analysis in its Fiscal Year 2006 and 2007 budgets for air and water monitoring equipment, as Montezuma County assumes no responsibility for the purchase, operation and data analysis of any equipment associated with this resolution, to be placed at sites throughout Montezuma County.

Commissioners voting aye in favor of the resolution were:

H Dewayne Findley Gerald Koppenhafer Larrie D Rule

Commissioners voting nay against the resolution were:

____________ ____________ ____________

Carol Tullis
County Clerk and Recorder
Montezuma County, Colorado

I certify that the above Resolution is a true and correct copy of same as it appears in the minutes of the Board of County Commissioners of Montezuma County, Colorado and the votes upon same are true and correct.

Dated this 13th day of June, 2005.

MONTEZUMA COUNTY SEAL 1889 COLORADO

Carol Tullis
County Clerk and Recorder
Montezuma County, Colorado

BUDGETS / FUNDING AND PROJECTED COSTS

Once the task of identifying suitable monitoring site locations has been completed, funding must be obtained to set up and operate the sites.

Capital costs and operating costs of a monitoring site will vary according to what parameters the site is measuring. The following spreadsheets show examples of capital and operating costs of two different monitoring sites.

The Shamrock site is under the jurisdiction of the IMPROVE **(Interagency Monitoring of Protected Visual Environments)** federal program and the Deming site is a state-run SLAMS **(State/Local Air Monitoring Stations)** site.

Funding of these types of sites usually comes from the federal government, but as federal budgets are cut, other resources have to be sought out. States have entered into partnerships with industry in order to fund monitoring activities. Various permit fees can be instituted or increased to obtain funds for monitoring. Private organizations can also be possible sources of funding.

A spreadsheet of possible funding sources is also shown. This spreadsheet lists organizations that are potential sources of funding, the geographic areas supported, applicant requirements, and the highest recent grants awarded. Most of these private funders require that grant recipients be non-profit, 501 (c) (3) organizations. Many of the funders also like projects that are collaborations and creative efforts capable of replication in other areas. They might support joint non-profit/governmental projects.

Shamrock Monitoring Site Capital Costs

Description	Qty	Unit Price	Total Price	NOTES
NOX Analyzer	1	10,000.00	10,000.00	
O3 Analyzer	1	0.00	0.00	From other site
NOx Calibration Devices	1	8,000.00	8,000.00	
IMPROVE Aerosol 4 Modules	1	16,000.00	16,000.00	
IMPROVE Housing Installation	1	5,000.00	5,000.00	
Climate Controlled Monitoring Shelter	1	9,000.00	9,000.00	
Data Logger	1	5,000.00	5,000.00	
Installation for Data Logger	1	5,000.00	5,000.00	
Laptop Computer	1	2,500.00	2,500.00	
Meteorology Station	1	4,000.00	4,000.00	
TOTAL			**$64,500.00**	

Shamrock Monitoring Site Annual Operating Costs

Description	Qty	Unit Price	Total Price	NOTES
Power and Phone	1	1,000.00	1,000.00	
Data Handling Contract	1	25,000.00	25,000.00	Data handling, digital photography, calibration, and reporting for NOx, Ozone, and Meteorology
IMPROVE Contract Fees	1	33,000.00	33,000.00	Analysis, reporting, and QA/QC
Labor	1	4,000.00	4,000.00	Total annual labor for: Weekly calibration, maintenance, and data downloads
TOTAL			**$63,000.00**	

Deming Monitoring Site Capital Costs

Description	Qty	Unit Price	Total Price
Thermo 42i NOX Analyzer	1	6,464.68	6,464.68
Thermo 49i O3 Analyzer	1	4,422.88	4,422.88
R&P TEOM PM10 Analyzer	1	17,500.00	17,500.00
Monitoring Shelter; Morgan Bldg	1	6,000.00	6,000.00
Intake Manifold	1	1,356.00	1,356.00
Sabio Calibrator	1	10,975.00	10,975.00
Sabio Keyboard	1	50.00	50.00
Sabio Zero Air Supply	1	2,447.00	2,447.00
Serial Cable; Sabio to Sabio	1	15.00	15.00
Null Modem Cable; Sabio to Computer	1	15.00	15.00
Solenoid Valves	2	215.00	430.00
Solenoid Valve Driver Cable	1	40.00	40.00
SS "T"'s (1/8" NPT to 1/4" OD)	2	17.60	35.20
SS Elbows (1/8" NPT to 1/4" OD)	4	15.00	60.00
Solenoid Valve Mounting Bracket	1	50.00	50.00
1/4" Teflon Tubing (50 ft)	0.2	350.00	70.00
1/8" Teflon Tubing (50 ft)	0.2	450.00	90.00
1/4" SS Plugs (caps)	4	7.50	30.00
1/8" SS Plugs (caps)	4	5.50	22.00
Glass Funnels	2	15.00	30.00
Surgical Tubing (50 ft)	0.2	40.00	8.00
EPA NO Protocol Gas Standard	1	258.00	258.00
Gas Regulator	1	625.00	625.00
Gas Cylinder Wall Mounting Bracket	1	25.00	25.00
Serial Cables; asst'd lengths, Air Monitors to Computer Moxa Cable	3	15.00	45.00
8-Port Moxa Card	1	300.00	300.00
Moxa Cable; 8 strand	1	55.00	55.00
Campbell Data Logger (CR10x)	1	1,779.00	1,779.00
12v Battery for Data Logger	1	25.00	25.00
Power Adapter for Data Logger	1	10.00	10.00
SC32B Optically Isolated Interface	1	80.00	80.00
APC UPS	1	200.00	200.00

Description	Qty	Unit Price	Total Price
Wireless Modem	1	500.00	500.00
Computer, monitor, keyboard, mouse	1	3,000.00	3,000.00
MET Tower Base; B-14	1	75.00	75.00
MET Tower	1	511.00	511.00
Lightning Rod	1	15.00	15.00
Grounding Rod	1	25.00	25.00
Rod Clamps	2	15.00	30.00
Tower Mast	1	35.00	35.00
Tower Cross Bar	1	35.00	35.00
Hardware Crosses, standard and offset	1	15.00	15.00
Solar Sensor (Li 200 SA 50)w/ Cable	1	215.00	215.00
Solar Sensor Mv Adapter (2220)	1	27.00	27.00
Solar Sensor Mounting Base	1	44.00	44.00
Solar Sensor Mounting Arm	1	65.00	65.00
Wind Monitor Unit (05305-5 AQ)	1	1,200.00	1,200.00
Wind Monitor Cable (50 ft)	1	50.00	50.00
Temperature Probes w/ Cable	2	425.00	850.00
Temperature Probe Aspirator	2	726.00	1,452.00
Power Installation	1	1,500.00	1,500.00
Security Fencing	1	1,600.00	1,600.00
TOTAL			**$ 64,756.76**

Deming Monitoring Site Annual Operating Costs

Description	Qty	Unit Price	Total Price
Power:	1	845.00	845.00
Communications:	1	830.00	830.00
Labor:	1	5,285.00	5,285.00
Consumables:	1	1,500.00	1,500.00
TOTAL			**$ 8,460.00**

Possible Funding Sources for Monitoring

Name & contact info	Areas Funded	Applicant requirements	Highest Recent Grant
PRIVATE SOURCES			
Ben & Jerry's Foundation (802) 846-1500 www.benjerry.com/foundation	national	501(c)(3)	$15,000
Patagonia, Inc. (805)643-8616 www.patagoniainc.com	Colorado	501(c)(3)	$20,000
Coutts & Clark Western Foundation (970) 259-6169 thinair@starband.net	SW CO multi-state	501(c)(3)	$5,000
William & Flora Hewlett Foundation (650) 234-4500 www.hewlett.org	national	501(c)(3)	$2,400,000
Microsoft Corp. Rocky Mountain Region (720) 528-1700 sandyp@microsoft.com	Rocky Mountain area	501(c)(3) local govt. entity?	$30,000
Anschutz Family Foundation (303) 293-2338 info@anschutzfamilyfoundation.org	Colorado, especially rural	501(c)(3)	$20,000
Eastman Kodak Charitable Trust (585)724-2434 www.kodak.com/us/en/corp/community.shtml	Colorado	501(c)(3)	$250,000

Name & contact info	Areas Funded	Applicant requirements	Highest Recent Grant
Greenlee Family Foundation (303) 444-0206 directorgff@aol.com	SW CO	501(c)(3)	$10,000
El Pomar Foundation 800-554-7711 grants@elpomar.org	Colorado	501(c)(3)	$1,550,000
Ford Motor Company Fund (313) 845-8711 fordfund@ford.com	National	501(c)(3)	$265,000

ADDITIONAL SOURCES FOR INFORMATION ON PRIVATE FUNDING FOR ENVIRONMENTAL PROJECTS

Environmental Grant Makers Association
(212 812-4260
shansen@ega.org

Community Resource Center, Inc.
(303) 623-1540
www.cramerica.org

SUMMARY OF SUGGESTIONS / PRIORITIES

Introduction

Air pollution is defined as a chemical, physical or biological agent that modifies the natural characteristics of the atmosphere.[1] Pollutants in the air may be natural in origin, such as blowing dust, forest fire smoke or organic compounds from vegetation. Of greater concern are anthropogenic, or man-made pollutants. These include chemicals and particulates from motor vehicles, smoke stacks, incinerators, refineries, industrial degreasing and pesticides, to name just a few. Pollutants may be classified as primary, where they are directly released form a source, or as secondary, where they are formed from reactions of other pollutants in the atmosphere. The health effects caused by air pollutants may range from subtle biochemical and physiological changes to difficulty breathing, wheezing, coughing and aggravation of existing respiratory and cardiac conditions. These effects can result in increased medication use, increased doctor or emergency room visits, more hospital admissions and premature death.[1]

Air pollution has been an issue to human health for centuries. One of the most famous episodes was the “Great Smog” that occurred in London, England in December 1952. Lasting for four days, over 12,000 people died either during the episode or in the months following as a result of the health effects.[2] While not the first air pollution smog to cause deaths, it was the largest to date and led to some of the first Clean Air Acts and air quality regulations in the world. In the United States, the first Clean Air Act was passed in 1963. However, it was not until the Clean Air Act of 1970 and with the creation of the U.S. Environmental Protection Agency (EPA) in the same year that real air pollution control came into full force.[3] This 1970 Clean Air Act was revised and expanded in 1990.

The U.S. EPA has set national ambient air quality standards (NAAQS) for six “criteria” pollutants. These are wide-spread pollutants from numerous and diverse sources that are considered harmful to public health and the environment. There are two types of NAAQS. Primary standards set limits to protect public health, including the health of “sensitive” populations such as asthmatics, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings.[4] The “criteria” pollutants are carbon monoxide, ozone, sulfur dioxide, nitrogen dioxide, lead and particulates (PM_{10} and $PM_{2.5}$). However, there are many other pollutants that can be found in the ambient air. Air toxics, which includes a variety of organic compounds and metals, is an area of increasing concern to human health. Visibility, while not directly a health-related concern, is an aesthetic concern and can be an indicator of other health-related pollutants. The sources and health/environmental impacts vary from pollutant to pollutant, though many are linked to each other.

Carbon monoxide is a colorless and odorless gas formed primarily from incomplete combustion of fuels. It is a product of motor vehicle exhaust, which contributes about 60 percent of all carbon monoxide emissions nationwide. Other sources of carbon monoxide emissions include industrial processes, non-transportation fuel combustion, and natural sources such as wildfires. With increasing emissions controls on motor vehicles and other sources, ambient carbon monoxide levels nationwide have been reduced significantly over the past two decades. Carbon monoxide enters the bloodstream through the lungs and reduces oxygen delivery to the body's organs and tissues. The health threat from carbon monoxide is most serious for those who suffer from cardiovascular disease. Visual impairment, reduced work capacity, reduced manual dexterity, poor learning ability, and difficulty in performing complex tasks are all associated with exposure to elevated carbon monoxide levels.[5]

Ozone is a highly reactive gas that is a form of oxygen. Though it occurs naturally in the stratosphere to provide a protective layer high above the earth, at ground-level it is the prime ingredient of smog.[6] Ozone is a secondary pollutant formed by the action of sunlight on carbon-based chemicals known as hydrocarbons, acting in combination with a group of air pollutants called oxides of nitrogen. As a result, ozone is generally a summer afternoon issue. Ozone reacts chemically with internal body tissues that it comes in contact with, such as those in the lung. It also reacts with other materials such as rubber compounds, breaking them down. Health symptoms include shortness of breath, chest pain when inhaling deeply, wheezing and coughing. Research on the effects of prolonged exposures to relatively low levels of ozone have found reductions in lung function, biological evidence of inflammation of the lung lining and respiratory discomfort.[7]

Sulfur dioxide is a gas that is formed when fuel containing sulfur (mainly coal and oil) is burned, and during metal smelting and other industrial processes. The major health concerns associated with exposure to high concentrations of sulfur dioxide include effects on breathing, respiratory illness, alterations in the lungs defenses, and aggravation of existing cardiovascular disease. Asthmatics and individuals with cardiovascular disease or chronic lung disease, as well as children and the elderly are particularly susceptible. In addition, sulfur dioxide is a major precursor to $PM_{2.5}$ particulates and acid rain.[8]

Nitrogen dioxide is a light brown gas that can become an important component of urban haze. Oxides of nitrogen (which includes nitrogen dioxide) usually enter the air as the result of high-temperature combustion processes, such as those occurring in automobiles and power plants. Nitrogen dioxide plays an important role in the atmospheric reactions that generate ozone. Home heaters and gas stoves also produce substantial amounts of nitrogen dioxide. Nitrogen dioxide can irritate the lungs and lower resistance to respiratory infections. Oxides of nitrogen are an important precursor to ozone, $PM_{2.5}$ particulates and acid rain.[9]

Lead is a metal that is used in a wide variety of commercial products. In the past, automotive sources were the major contributor of lead emissions to the atmosphere. As a result of unleaded fuels now being used, ambient lead levels have decreased significantly. Today, metals processing is the major source of lead emissions to the atmosphere. The highest concentrations of lead are found in the vicinity of nonferrous and ferrous smelters, battery manufacturers, and other stationary sources of lead emissions. Exposure to lead occurs mainly through the inhalation of air and the ingestion of lead in food, water, soil, or dust. It accumulates in the blood, bones, and soft tissues. Because it is not readily excreted, lead can also adversely affect the kidneys, liver, nervous system, and other organs. Excessive exposure to lead may cause neurological impairments such as seizures, mental retardation, and/or behavioral disorders. Recent studies also show that lead may be a factor in high blood pressure and subsequent heart disease.[10]

Particle pollution is a mixture of microscopic solids and liquid droplets suspended in the air. This pollution, also known as particulate matter, is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, soil or dust particles, and allergens (such as fragments of pollen or mold spores).[11] Particulate pollution comes from such diverse sources as factory and utility smokestacks, vehicle exhaust, wood burning, mining, construction activity, and agriculture.[12] The size of particles is directly linked to their potential for causing health problems. Small particles less than 10 micrometers in diameter pose the greatest problems, because they can get deep into your lungs, and some may even get into your bloodstream. Exposure to such particles can affect both your lungs and your heart. Particulate matter air pollution is especially harmful to people with lung disease such as asthma and chronic obstructive pulmonary disease (COPD), which includes chronic bronchitis and emphysema. Exposure to particulate air pollution can trigger asthma attacks and cause wheezing, coughing, and respiratory irritation in individuals with sensitive airways. Larger particles are of less concern, although they can irritate your eyes, nose, and throat.

Toxic air pollutants, also known as hazardous air pollutants, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental effects. Examples of toxic air pollutants include benzene, which is found in gasoline; perchlorethlyene, which is emitted from some dry cleaning facilities; and methylene chloride, which is used as a solvent and paint stripper by a number of industries. Examples of other listed air toxics include dioxin, asbestos, toluene, and metals such as cadmium, mercury, chromium, and lead compounds.[13] There are no NAAQS for toxic air pollutants. Instead, they are regulated nationally by requiring the use of pollution controls on sources.

Visibility is defined as the greatest distance at which a black object can be seen and recognized when observed against a background fog or sky. From an aesthetic perspective, visibility represents not just visual range, but rather the overall visual experience of a scene.[14] Thus, visibility issues are not directly a health impact. However, many of the pollutants that cause visibility degradation may cause health impacts. In addition to primary particulates, secondary particulates are a part of visibility degradation. These secondary particulates can be formed from sulfur dioxide and nitrogen dioxide, both of which are criteria pollutants.

Both N and sulfur (S) oxides can form “acid rain” and lead to acidification of surface and groundwater and soils. S oxides primarily are emitted to the atmosphere by burning of fossil fuels.

Increased deposition of atmospheric N can result in high levels of nitrate in surface and ground water, shifts in species, decreased plant health, and eutrophication (i.e., fertilization) of otherwise naturally low-productivity ecosystems.

Analysis and Interpretation of Existing Data

Meteorology

Meteorological data are collected at a number of different locations in the Four Corners region.

In looking at the annual wind roses, it is evident that some sites are more influenced by local topography than others. An example is the Cortez CoAgMet site, which is located in the valley between Sleeping Ute Mountain and Mesa Verde and is subjected to definite channeling effects. Another example is the U.S. Forest Service Shamrock site, which is located on the side of a hogback ridge. It can also be seen that the strongest winds are generally from a more westerly direction than an easterly one. From the daytime wind roses, there are general westerly or northerly/southerly components to the winds. In comparison, the nighttime wind roses show more of general easterly to northerly components. These trends are expected based on prevailing regional wind patterns as well as more local convection heating and cooling patterns along with topography.

These wind roses can be broken down even further, such as only for summer afternoon periods when ozone levels are expected to be highest (see summer afternoon wind rose maps). These wind roses show, in general, a predominant westerly to southwesterly component. As mentioned previously, some sites still exhibit wind patterns that are strongly influenced by local topography rather than more regional winds. However, these types of plots are useful in describing what may happen with air pollution flows during different periods of time. While not performed for this analysis, additional seasonal plots could be dome, such as for winter when inversions are more prevalent.

Ozone and Precursor Gases

Ground level ozone is currently monitored on a continuous basis at nine locations in the Four Corners region, with seven sites being in a core area. For regulatory comparisons to the NAAQS, continuous analyzers that have been designated as “equivalent’ or “reference” by the U.S. Environmental Protection Agency (EPA) are used.

Currently, ambient ozone levels in the Four Corners region are below the level of the current NAAQS (see trends and standards graphs). However, at Mesa Verde and one Southern Ute site there is an increasing trend, and the two newer sites (USFS, Navajo Lake) are recording higher levels. Many of the sites would be above the level of a reduced NAAQS, as proposed by CASAC.

With ozone typically having peak concentrations in the summer afternoons when sunlight is strongest, pollutant roses were developed accordingly and were placed on both political boundary and topographic base maps (see pollutant rose maps). As can be seen from these pollutant rose maps, ozone at the three southern core area sites in New Mexico and the Mesa Verde site in Colorado show predominantly westerly wind directions in this summer afternoon timeframe. This generally mirrors the predominant San Juan River drainage. The two Southern Ute Tribe sites and the Forest Service Shamrock site appear to be heavily influenced by local topography. Thus, based on these pollutant roses, it is likely that ozone concentrations could also be high further to the east and north of the New Mexico Navajo Lake site, further up the San Juan River and Piedra River drainages. While no monitoring exists to confirm or deny, winds could also flow up other drainages in summer afternoons, including the Dolores and Animas Rivers.

For ozone precursor gases, NOx monitoring currently exists at six sites in the Four Corners region. NO_2 levels have been fairly steady over the years at most sites, at a level well below the NAAQS. At two sites in particular, San Juan Substation, NM and Bloomfield, NM, the NO_2 levels do appear to be increasing over time.

NO, unfortunately, has not been reported consistently as it is not designated a criteria pollutant. However, NO levels do appear to be increasing at both Southern Ute Tribe sites, Ignacio and Bondad. These increases in NO and NO_2 are of concern due to the potential for increased ozone formation and also indicates that there are increased combustion sources in the area, possibly due to oil and gas development and increased traffic.

VOC baseline monitoring for San Juan County, New Mexico was conducted in 2004 and 2005 at three sites. One site was near Bloomfield, NM near some industrial sources, a second near the San Juan power plant and the third site was near Navajo Lake, in an oil and gas development area. Results showed that alkane concentrations dominated, especially ethane and propane. The biogenic compound isoprene and the highly reactive VOC compounds, ethylene and propylene, were not present in significant quantities.

Mercury

Total mercury in wet deposition has been monitored at Mesa Verde National Park since 2002 as part of the Mercury Deposition Network. Results show mercury concentrations among the highest in the nation during certain years. Precipitation is relatively low, however, so mercury in wet deposition is moderate. Mercury concentrations have been measured in snowpack at a few sites in the San Juan Mountains by the USGS and moderate concentrations similar to the Colorado Front Range have been recorded. Mercury concentrations in sport fish from several reservoirs have exceeded the 0.5 microg/g action level resulting in mercury fish consumption advisories for water bodies including McPhee, Narraguinnep, Todden, Navajo, Sanchez and Vallecito Reservoirs and segments of the San Juan River. Atmospheric deposition just to the surface of McPhee and Narraguinnep Reservoirs (i.e., not including air deposition to the rest of the watershed) is estimated to contribute 8.2% and 47.1% of total mercury load to these water bodies, respectively.

Nitrogen and Sulfur Compounds

Currently, monitoring stations for N, S, and H+ in wet deposition exist at Mesa Verde National Park (since 1981), Molas Pass (since 1986), and Wolf Creek Pass (since 1992) as part of the National Atmospheric Deposition Program. Dry deposition of N and S, which is especially important in arid regions (Fenn et al. 2003), has been monitored since 1995 at Mesa Verde NP as part of the Clean Air Status and Trends Network.

Trends of sulfate concentrations in wet deposition show either a decrease over time or no change at monitoring stations in the vicinity of the Four Corners region. Conversely, trends of nitrate and ammonium concentrations in wet deposition appear to be stable or increasing. In general, N in wet deposition in the Four Corners and San Juan Mountain region currently is at or above the 1.5 kg/ha/yr ecological critical load discussed above for Rocky Mountain National Park. Dry deposition data from Mesa Verde NP indicate that, for the period 1997-2000, dry deposition contributed about half of the total inorganic nitrogen deposition and about one-third of the total sulfur deposition. The short data record is insufficient to detect trends over time for dry deposition. Model simulations of total wet plus dry deposition of N in the western United States indicate a possible hotspot for N deposition in SW Colorado.

Visibility

Currently, there are four sites within the Four Corners region that monitor visibility: Mesa Verde National Park, the Weminuche Wilderness (near Purgatory,) the Shamrock Mine (southeast La Plata County,) and Canyonlands National Park. Of these four sites, only the Forest Service monitoring station at the Shamrock Mine records images, and is included in IMPROVE’s optical and scene monitoring network. Additionally, because the Canyonlands site lies on the margin of the Four Corners Region, and it is also located at a comparatively lower elevation north of the Blue Mountains, it may not serve as the best indicator of visibility trends in the Four Corners proper.

Preliminary analysis of deciview trends at Mesa Verde, and also of visibility-impairing gasses and particulates as monitored at other sites, does not reveal a clear trend of how visibility might be changing in the Four Corners. This appraisal is not concomitant with the observations of many area residents. It may be indicative of monitoring gaps that exist in the Four Corners, and it has led to the perception by members of the Task Force Monitoring Group that a comprehensive, detailed analysis of all available data regarding visibility is greatly needed.

Despite that ambiguity, however, there are a few details worth noting. In September of 2005, the Interim Emissions Workgroup of the Four Corners Air Quality Task Force recommended that an ambient monitoring program for gaseous ammonia be initiated in the Four Corners region. The purpose of this program is to set a current baseline of ambient gaseous ammonia concentrations in the Four Corners, that can be compared to monitored values in approximately 3-5 years after the implementation of NOx controls (e.g. NSCR) on oil and gas equipment. The use of NSCR may increase ammonia emissions in the area, but these emissions have not been quantified and may or may not significantly affect visibility. Ammonia at high enough concentrations can contribute to worsening visibility by forming PM 2.5 ammonium nitrates and ammonium sulfates.

Additionally, the implementation of new SO_2 controls at the San Juan Generating Station in 1999 has successfully reduced SO_2 emissions in the area. Because of the high impact that SO_2 can have upon visibility, that reduction has likely made a positive impact upon visibility conditions in the Four Corners. However, changes in monitoring conditions at San Juan Substation have not been limited to a decrease in SO_2. Concurrently, it appears that NOx concentrations have risen, and now dominate over SO_2.

Carbon Monoxide, PM_{10} and Other Common Pollutants

Carbon Monoxide

Carbon monoxide in the ambient air is currently monitored on a continuous basis at only one site in the Four Corners region. This is at the Southern Ute Tribe's Ignacio site in southern Colorado. Monitoring was performed at New Mexico's Farmington site, but was discontinued in 2000. Ambient carbon monoxide levels in the Four Corners region are well below the level of the current NAAQS.

PM_{10}

PM_{10} in the ambient air is, historically, the most heavily monitored pollutant in the Four Corners region. Most of the monitoring has been performed using filter-based "high-volume" samplers that collect 24-hour samples and most of the data are available on EPA's Air Quality System. Ambient PM_{10} levels in the Four Corners region are well below the level of the current and former NAAQS.

Others

No monitoring for lead exists in the Four Corners region. Due to the introduction of unleaded gasoline in the 1970's, ambient lead levels have decreased to levels that are near instrument detection levels. Likewise, no monitoring exists for other pollutants such as carbon dioxide, HAPs or pesticides.

<u>Suggestions for Future Monitoring Work</u>

Meteorology

No significant data gaps exist for meteorological monitoring in the Four Corners region, with the exception of southwestern Utah and northeastern Arizona. No suggestions for additional monitoring of meteorological parameters are currently being proposed.

Ozone and Precursor Gases

While it would appear that there is a sufficient ozone monitoring network in the Four Corners region, some areas are lacking. Pollutant roses were developed to determine the directions from which ozone precursors are most likely to be transported by wind. Ozone monitoring currently exists in the major oil and gas development areas, but little downwind ozone monitoring currently exists.

VOCs are also a gap, as the short-term studies in 2004 and 2005 were located toward the southern edge of the oil and gas development area, or not in the development area at all. While emissions inventories can provide an estimate of total VOCs that may be released to the atmosphere, these are primarily based on predicted emissions, not on actual measurements. This is a concern as different VOCs have different ozone formation potentials and the oil and gas development has dramatically increased in the region since these studies.

<u>Suggestions for Future Monitoring Work for Ozone:</u>

Install and operate two or three long-term continuous monitoring stations for ozone. One station would be located upstream of Navajo Lake, in the San Juan River drainage toward Pagosa Springs, CO, or in the Piedra River drainage, toward Chimney Rock, CO. This area is toward the northeastern portion of the Four Corners region and is downwind of many VOC precursor gas sources from oil and gas development. The second station would be located to the north of Cortez. This area is in the north-central portion of the Four Corners region and is downwind of both an urban area and any precursor gas emissions that would funnel up between Sleeping Ute Mountain and Mesa Verde. If funding exists, a third site in Arizona on Navajo Nation land, in the southwest portion of the Four Corners area, is recommended. This site, possibly at Canyon de Chelly National Monument, would be to the west of a high ozone area as determined in the 2003 passive ozone study and would provide a good representation of regional ozone levels entering the Four Corners area. Each site, including shelter and instrumentation, would cost approximately $15,000 to $20,000 (total = $45,000 to $60,000). Annual operating costs (not including field personnel) would be approximately $1,500 per site (total = $3,000).

Perform an ozone saturation study using passive samplers across the entire Four Corners region to determine areas of highest ozone concentration. This would help determine if existing or new continuous monitoring sites are located in appropriate areas or if continuous ozone monitors need to be added or moved. It is expected that at least 20 passive ozone sites over the four-state region would be needed. Running for 30 days during a summer, the approximate cost would be $22,000 (not including field personnel time).

Perform monitoring for VOCs (in particular NMOCs) and carbonyls in the oil and gas development areas to determine the actual constituents in the emissions from wellheads, leaks and tanks. This would help in determining the potential for ozone formation from these compounds. This suggestion also includes follow-up monitoring for VOCs, both in and near the oil and gas development area, to compare to the 2004 and 2005 baseline data from San Juan County, New Mexico. A minimum of four to five sites is recommended; two sites in the oil and gas development area, one background site and one or two follow-up sites. For a year of monitoring, every sixth day, the approximate cost (not including field personnel time) would be $45,000 per site (total = $180,000 to $225,000).

Mercury

Very little data exists for the Four Corners Region with which to assess current risks and trends over time for mercury in air deposition, ecosystems, and sensitive human populations. No data exists for mercury in deposition at high elevations. Wet deposition of mercury at Mesa Verde National Park may not portray the situation in the mountains where mercury may be deposited at higher concentrations and total amounts because of greater rates of precipitation and the process of cold condensation, which causes volatile compounds to migrate towards colder areas at high elevation and latitude[7]. No information about total mercury deposition from the atmosphere (i.e., including dry deposition) exists for low or high elevations in the Four Corners Region. Furthermore, analysis of sources of air deposition of mercury is lacking. Except for a handful of reservoirs, no information exists for incorporation of mercury into aquatic ecosystems and subsequent effects on food-webs. No systematic effort exists to document mercury impacts in a wide range of water bodies over space and time. Lastly, impacts of mercury exposure to human populations are unknown.

<u>Suggestions for Future Monitoring Work for Mercury:</u>

1. Install and operate a long-term monitoring station for mercury in wet deposition for a location at high elevation where precipitation amounts are greater than the site at Mesa Verde NP. Co-location of the collector with the NADP site at Molas Pass would provide data pertinent to Weminuche Wilderness and the headwaters of Vallecito Reservoir. This monitor would be part of the Mercury Deposition Network (MDN). Upgrading the NADP monitoring equipment at Molas Pass to include the MDN specifications would cost $5,000 to $6,000, while annual monitoring costs are $12,112 plus personnel as of September 2006.

2. Install and operate a long-term monitoring station for mercury in total deposition (wet and dry) for at least one MDN station in the Four Corners Region. Speciated data will be collected and analyzed as is feasible. The MDN is currently developing this program and costs are anticipated at about $50,000 per year.

3. Support multi-year comprehensive mercury source apportionment study to investigate the impact of local and regional coal combustion sources on atmospheric mercury deposition. This type of study would require additional deposition monitoring (i.e., suggestions 1 & 2 above). Speciated data will be collected and analyzed as is feasible. A mercury monitoring and source apportionment study was recently completed for eastern Ohio. (http://pubs.acs.org/cgi-bin/asap.cgi/esthag/asap/html/es060377q.html9). Costs TBD.

4. Support a study of mercury incorporation and cycling in aquatic ecosystem food-webs, including total and methyl mercury in the food-webs of lakes and wetlands. This option includes studies that determine which ecosystems currently have high levels of total and methyl mercury in food-web components, how mercury levels in ecosystems change over time, where the mercury is coming from, and what conditions are causing the mercury to become methylated (the toxic form of mercury that bio-accumulates in food-webs). This information would allow tracking of mercury risks over time and space and serves as the basis for predicting future impacts. Existing reservoir studies and the upcoming MSI investigation serve as a starting point to build a collaborative and systematic approach. Costs TBD.

5. Support continued studies of mercury concentrations in sensitive human populations in the region to understand what exposure factors increase likelihood of unhealthy mercury levels in the body. Dr. Richard Grossman's study serves as a starting point to continue this effort. Costs TBD.

6. Form a multi-partner Mercury Advisory Committee that would work collaboratively to prioritize research and monitoring needs, develop funding mechanisms to sustain long-term mercury studies, and work to communicate study findings to decision-makers. The Committee would include technical experts and stakeholder representatives from States, local governments, land management agencies, watershed groups, the energy industry, etc.

Nitrogen and Sulfur Compounds

While data for N in wet deposition exist from multiple sites in the region, dry deposition is studied only at Mesa Verde National Park, which does not represent higher-elevations common near the Four corners region. Data concerning ecological effects of N deposition are very sparse for both high and low elevations and the limited data that do exist have not been analyzed adequately. No data exists for N and S deposition in the vicinity of emission sources. For example, no monitoring of N and S in wet or dry deposition occurs in NW New Mexico with the exception of Bandelier National Park.

Suggestions for Future Monitoring Work for Nitrogen and Sulfur Compounds:

Continue monitoring for N, S and H+ in wet deposition via the NADP at the Molas Pass, Wolfe Creek Pass and Mesa Verde National Park sites. Consider adding a site closer to emissions sources in NW New Mexico.

Initiate long-term monitoring / modeling of N and S in dry deposition via the Clean Air Status and Trends Network (CASTNet) at a site such as Molas Pass, which is at higher elevation than the one existing site at Mesa Verde NP. Consider adding an additional site closer to emissions sources in NW New Mexico.

Complete a full analysis of existing Wilderness Lakes data, including spatial and temporal trends and correlation of measurements with watershed or lake characteristics.

Support a suite of ecological studies in order to measure potential harmful effects of N deposition on natural resources across an elevation gradient. The studies should include an observational component aimed at documenting changing ambient conditions, but experimental manipulations should also be used to understand cause and effect relationships in addition to potential future responses. These studies should be modeled after those conducted in the Colorado Front Range, California, etc.

Visibility

Most visibility monitoring in the Four Corners is unevenly distributed (or restricted) to Class I areas. Therefore, visibility monitoring within these Class I areas is not conducive of a regional trends assessment, especially because they are based on a very few site-specific particulate measurements. Furthermore, the regional monitoring of visibility is desirable, because it can assist with the protection of Class I areas and EPA's regional haze rule. Additionally, regional monitoring of visibility will better address the value that citizens place upon the vistas that exist outside of Class I areas, while recognizing how visibility impacts citizens' perceptions of air quality as a whole. In sum, it is highly desirable that we consider how visibility monitoring in the Four Corners region can be perfected, with the intent of making a *strong regional assessment*.

1. It is recommended that the monitoring sites at Mesa Verde and in the Weminuche resume photographic documentation.

2. Many previous studies of visibility in the Four Corners relate only to site-specific locations, and often conflict in their findings. A comprehensive assessment of historical data is needed, in order to determine regional trends or changes in visibility. Currently, it is very difficult not only to establish regional trend analyses, but also to compare them to historical baseline data.

3. Additional visibility monitoring should be established at locations in the region other than what exists in Class I areas. This additional monitoring:

   D. could be incorporated into existing monitoring sites;
   E. should include photographic documentation;
   F. and, it should specifically consider how topographical variations impact the measurement of visibility.

4. The apparent contribution of NOx emissions to wintertime visibility impairment is recommended for further study.

Carbon Monoxide, PM_{10} and Other Common Pollutants

No suggestions for additional monitoring of carbon monoxide, PM10 and other common pollutants are currently being proposed.

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RESPONSES TO "MONITORING" COMMENTS

(by Gordon Pierce)

1. Kandi & David LeMoine, 7/17/2007
"… I reviewed what the monitoring group put together, and I think they did an excellent work."

The workgroup would like to say thanks! (No changes to the report.)

2. BP, 7/13/2007
"While the Draft Report suggestion for addition of new monitoring sites will provide valuable insight to understanding air quality in the region, a detailed analysis of current monitoring data also needs to be conducted to identify trends in air quality. In addition, analyzing trends in monitoring data in conjunction with changes in emissions will provide an important understanding of atmospheric processes. Also, it may be possible to evaluate monitoring data to assist in understanding source receptor relationships.
Confidence limits need to be developed based on monitoring accuracy and precision to determine if observed trends in data are statistically significant or simply random variations in analytic methods. There are also bounding calculations that could be performed that may assist in determining how changes in emissions may change visibility. Such calculations would entail using the IMPROVE data and ratioing the concentrations to calculate the improvement in visibility and establish an upper bound of visibility improvement.
It is recommended that the Task Force conduct a detailed analysis of the IMPROVE monitoring data in the region since BP believes that such an analysis would assist in developing meaningful strategies for improving air quality in the region. BP would welcome the opportunity to assist in establishing a scope of work for such an activity."

(Full response to be written by Sylvia Oliva.) The workgroup agrees that it would be nice to do more with trends analyses, confidence limits and IMPROVE data analyses. However, this was much more work than the workgroup had time to do. (No changes to the report.)

3. Jeanne Hoadley, 7/10/2007
"I would find it helpful if the wind roses on the maps were labeled with the station name."

The workgroup debated extensively as to how much information should be included on the wind rose maps. It was felt that adding more information would make the maps too cluttered and that station names should be presented separately. Thus, maps with only the station names and elevations are presented immediately preceding the wind rose maps. (No changes to the report.)

4. Jeanne Hoadley, 7/10/2007
"Under existing ozone data for the four corners region it says a Navajo Nation site is scheduled to begin operating in Shiprock but doesn't say when. If it is scheduled this implies we know when and we should say. If we don't know when we should say it is expected to begin operating soon."

At the time this subsection was written, there was not a specific date as to exactly when the Navajo Nation would be able to get their new air monitoring site fully operational. In further conversations with the Navajo Nation, the date is still uncertain due to electrical power issues. The report will be revised so that the text reads that the site is planned to commence operation by the end of 2007. (See report for revision under OZONE AND PRECURSOR GASES subsection, "Existing Ozone Data for the Four Corners Region".)

5. Jeanne Hoadley, 7/10/2007
"Under existing ozone data for the four corners region it says a Navajo Nation site is scheduled to begin operating in Shiprock but doesn't say when. If it is scheduled this implies we know when and we should say. If we don't know when we should say it is expected to begin operating soon.
The next sentence has a typo...the "closest" Arizona site."

Thank you for catching the typo. The word will be revised from "closes" to "closest". (See report for revision under OZONE AND PRECURSOR GASES subsection, "Existing Ozone Data for the Four Corners Region".)

6. Mark Jones, 7/10/2007
"Comment on behalf of Roy Paul, "Why is there no ozone monitoring on the Western Slope of Colorado?""

There are questions as to whether this comment is referring to the southwest/Four Corners area of Colorado or further north, such as around Mesa and Garfield counties in Colorado. For the southwest/Four Corners area, which is the focus of this workgroup, ozone monitoring is currently performed at four locations in Colorado. These locations are shown on the map in the "Ozone and Precursor Gases" subsection of the report. In addition, for recommendation #2 in the subsection, a passive ozone study was performed in the area during August 2007 using monies recently appropriated by the Colorado legislature. A revision to address this is made under recommendation #2. (See report for revision under OZONE AND PRECURSOR GASES subsection, recommendation #2.)

7. Jeanne Hoadley, 7/10/2007
"The pollutants in the header seem to be out of place in this table."

This appears to have been an issue with the software and comment version of the report on the website. The tables are correct in the actual report. (No changes to the report.)

8. Jeanne Hoadley, 7/10/2007
"Again the header in this table is messed up, making it impossible to understand."

This appears to have been an issue with the software and comment version of the report on the website. The tables are correct in the actual report. (No changes to the report.)

9. Jeanne Hoadley, 7/10/2007
"Mercury- Rationale and Benefits. It is not clear to me why Weminuche Wilderness is singled out here...there are many other Class 1 areas in or near this region."

(Full response to be written by Koren Nydick.) The commenter is correct in that other Class 1 areas are in the region. Weminuche was simply being used as an example. Mercury will be clarified in the report and other Class 1 areas will also be listed or mapped. (See revisions from Koren Nydick.)

Response to BP's Comments

(by Sylvia Oliva)

"Detailed analysis [analyses] of current monitoring data" including trends and back trajectories are already available on the Interagency Monitoring for the Projected Visual Environment, IMPROVE, web site (http://vista.cira.colostate.edu/improve/). Mesa Verde National Park data reaches back to the early 1990s. The highest standard possible for "accuracy and precision" of IMPROVE filters is well-established by the monitoring analysis agency: Crocker Nuclear Labs, University of California at Davis.

IMPROVE filter analyses include x-ray spectroscopy and related techniques. The filters themselves are of several different materials to best trap different aerosols and particulates. (This is why, unfortunately, data availability is traditionally in arrears for 12 to18 months.) Furthermore, any changes in filter composition or analysis protocol through the years are precisely notated in the preamble for accessing raw data for either single or groups of IMPROVE sites, single or groups of parameters.

It indeed would contribute to important understanding of atmospheric processes to take IMPROVE trend data (already available as previously mentioned) with emissions changes to assist in "understanding source-receptor relationship[s]." The caveat, here is that Mesa Verde data is not truly representative of visibility impairment in that the park's physical location (and therefore its IMPROVE site) is really not within the impairment atmosphere, contrary to other parks, e.g. Grand Canyon NP, Yellowstone, NP, or the Great Smokies NP. Rather, the visitor at Mesa Verde sees visibility impairment from outside. Likely, Mesa Verde IMPROVE data might be matched as background with other IMPROVE station data.

So, such a tremendously laudable project correlating trends with emissions sources is not within the present financial means and scope of the current task force.

Dramatic improvements in computer processing power the past two years will quite revolutionize modeling techniques. If these techniques are already incorporated into modeling software, establishing "an upper bound of visibility improvement" may well be a more realistic task than heretofore. (See Marufu, L. T. et al, The 2003 North American electrical blackout: An accidental experiment in atmospheric chemistry, Geophys. Res. Lett., 31, L13106, doi:10.1029/2004GL019771. "The dramatic improvement in air quality during the blackout may result from underestimation of emissions from power plants, inaccurate representation of power plant effluent in emission models or unaccounted for atmospheric chemical reaction(s).")

Appendices

Acronyms

Acronyms

μeq/L	micro-equivalents per liter
μg/L	micrograms per liter
$\mu g/m^3$	micrograms per cubic meter
<	less than
>	greater than
°C	degrees Centigrade
°F	degrees Fahrenheit
4CAQTF	Four Corners Air Quality Task Force
AAQS	Ambient Air Quality Standards
AC	Alternating Current
ACI	Activated Carbon Injection
A/F	Air/Fuel
AFR(s)	Air/Fuel Ratio
AFRC(s)	Air/Fuel Ratio Controllers
AFUDC	Allowance For Funds During Construction
aka	also known as
ANGEL	Airborne Natural Gas Emission LIDAR
APCD	Air Pollution Control Division
APD	Application for Permit to Drill
APS	Arizona Public Service
AQI	Air Quality Index
AQRV	Air Quality Related Value
AQS	Air Quality Standard
AQTSD	Air Quality Technical Support Document
ARM	Air Resource Management
ARS	Agricultural Resource Service
ASTM	American Society for Testing and Materials
ASU	Air Separation Unit
AWMA	Air & Waste Management Association
AZ	Arizona
B&W	Babcock and Wilcox
BACM	Best Available Control Measure
BACT	Best Available Control Technology
BAGI	Backscatter Absorption Gas Imaging
BART	Best Available Retrofit Technology
Bbl/day	barrels per day
Bcf	billion cubic feet
bhp	Brake Horsepower
BHP	BHP Billiton, Ltd.
BLM	Bureau of Land Management (U.S. Department of the Interior)
BMP(s)	Best Management Practices
BTEX	Benzene, Toluene, Ethyl-benzene, Xylene
Btu/kw-hr	British Thermal Units per Kilowatt Hour
CA	California
CAA	Clean Air Act
Ca	Calcium
CaCl	Calcium Chloride
CaCO3	Calcium Carbonate
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CALPUFF	California PUFF Dispersion Model
CaO	Calcium Oxide (Lime)
CARB	California Air Resources Board

CARE	Citizens Against Ruining our Environment
CAS	Chemical Abstracts Service
CASAC	Clean Air Scientific Advisory Committee
CaSO4	Calcium Sulfate
CASTNET	Clean Air Status and Trends Network
CB-DPF	Catalyst-Based Diesel Particulate Filter
CBM	Coal Bed Methane
CBNG	Coalbed Natural Gas
CCAG	Climate Change Advisory Group (New Mexico)
CCC	Colorado Climate Center
CCR	Colorado Code of Regulations
CCS	Carbon Capture and Sequestration
CCV	Closed Crankcase Ventilation
CCX	Chicago Climate Exchange
CDNR	Colorado Department of Natural Resources
CDOT	Colorado Department of Transportation
CDOW	Colorado Division of Wildlife
CDPHE	Colorado Department of Public Health and Environment
CDPHE-APCD	Colorado Department of Public Health and Environment – Air Pollution Control Division
CE	Cumulative Effects
CEC	California Energy Commission
CEDF	Clean Environment Development Facility
CEM	Continuous Emission Monitor
CEMS	Continuous Emission Monitoring System
CFB	Circulating Fluidized Bed and/or Coal-fired Boiler
CFLs	Compact Fluorescent Light bulbs
CFR	Code of Federal Regulations
Cfs	Cubic Feet per Second
CGS	Colorado Geological Survey
CH2	Methylene
CH3	Methyl Group
CH4	Methane
CHP	Combined Heat and Power
CI	Compression Ignition
Cl	Chloride
CNG	Compressed Natural Gas
CO	Carbon Monoxide and/or Colorado
CO2	Carbon Dioxide
COA	Conditions of Approval
CoAgMet	Colorado Agricultural Meteorological Network
COBRA	CO-Benefits Risk Assessment
COE	Cost of Energy
COGCC	Colorado Oil and Gas Conservation Commission
COM	Continuous Opacity Monitor
CPANS/ PNWIS	Canadian Prairie and Northern Section/Pacific Northwest International Section
CTG	Control Techniques Guideline
CWCS	Comprehensive Wildlife Conservation Strategy
DC	Direct Current
DCS	Distributed Control System
DEIS	Draft Environmental Impact Statement
DEP	Department of Environmental Protection
DEQ	Department of Environmental Quality
DER	Distributed Energy Resources
DIAL	Differential Absorption LIDAR
DLN	Dry Low NOX

DO	Dissolved Oxygen
DOAS	Differential Optical Absorption Spectroscopy
DOC	Diesel Oxidation Catalyst
DOE	U.S. Department of Energy
DPA	Dinè Power Authority
DREF	Desert Rock Energy Facility
DPF	Diesel Particulate Filter
DR	Demand Response
DRMP	Draft Resource Management Plan
DSIRE	Database of State Incentives for Renewable Energy
DV	Deciview
E	East
E&P	Exploration and Production
EA	Environmental Assessment
EAC	Early Action Compact
EBETS	Economic Incentives-Based Emission Trading System
ECBMR	Enhanced Coal Bed Methane Recovery
ECM	Electronic Control Module
EE	Energy Efficiency
EEREC	Energy Efficiency, Renewable Energy and Conservation
EGR	Exhaust Gas Recirculation
eGRID	Emissions and Generation Integrated Resource Database
EGU	Electric Generating Unit
EIS	Environmental Impact Statement
ENGR	Enhanced Natural Gas Recovery
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
EPCA	Energy Policy and Conservation Act
EPD	Environmental Protection Division
EPRI	Electric Power Research Institute
ERMS	Emission Reduction Market System
ESP	Electrostatic Precipitator
ETC	Environmental Technology Council
ETS	Emission Trading System
F	degrees Fahrenheit
F-T	Fischer-Tropsch
FAQs	Frequently Asked Questions
FBC	Fuels Borne Catalyst
FCOTF	Four Corners Ozone Task Force
FCPP	4 Corners Power Plant
FEIS	Final Environmental Impact Statement
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FLAG	Federal Land Managers' AQRV Workgroup
FLM	Federal Land Manager
FR	Federal Register
FS	Forest Service (U.S. Department of Agriculture)
Ft	feet
FTF(s)	Flow Through Filter
FY	Fiscal Year
G	gram
g/bhp-hr	grams per brake horsepower-hour
g/hp-hr	grams per horsepower-hour
GF	Growth Fund
GHG(s)	Greenhouse Gases
GIS	Geographic Information System

GOR	Gas Oil Ratio
GVW	Gross Vehicle Weight
GWh/yr	Gigawatt hours per year
H+	Hydrogen ion
H2O	Water
H2S	Hydrogen Sulfide
H2SO4	Sulfuric Acid
HAP(s)	Hazardous Air Pollutants
HC(s)	Hydrocarbons
HF	Hydrogen Fluoride
Hg	Mercury
HCHO	Formaldehyde
HNO3	Nitric Acid
hp	Horsepower
HRSG	Heat Recovery Steam Generator
HRVOC(s)	Highly Reactive Volatile Organic Compounds
I&M	Inspection and Maintenance
IBEMP	Innovation Technology and Best Energy-Environment Management Practices
ICE	Internal Combustion Engine
IGCC	Integrated Gasification Combined Cycle
IMPROVE	Interagency Monitoring of Protected Visual Environment
ISA	Instrument Systems and Automation Society
ISCST3	Industrial Source Complex – Short Term Dispersion Model, Version 3
IWAQM	Inter-Agency Work Group on Air Quality Modeling
K	One Thousand Dollars or Potassium
kg/ha-yr	Kilograms per Hectare-Year
km	kilometer
Kwh	kilowatt hour
LAER	Lowest Achievable Emission Rate
lb	pound
lbs/mmBtu	pounds of emissions/million btu heat input
lbs/MWh	pounds of emission/Megawatt-hour
LDAR	Leak Detection and Repair
LEED	Leadership in Energy Efficiency and Design
LiCl	Lithium Chloride
LIDAR	Light Detection and Ranging
LLC	Limited Liability Company
LNC	Lean NOX Catalyst
LNG	Liquefied Natural Gas
LoTOx	Low Temperature Oxidation Technology
LP	Limited Partnership
LPG	Liquefied Petroleum Gas
LTO	Low Temperature Oxidation
LWV	League of Women Voters
MACT	Maximum Achievable Control Technology
MC	Multi-Contact
mcf	one thousand cubic feet
MDN	Mercury Deposition Network
Mg	Magnesium
mg/L	milligrams per liter
mg/m3	micrograms per cubic meter
microg/g	micrograms per gram
MIT	Massachusetts Institute of Technology
MM	One Million Dollars
Mm^{-1}	Inverse Megameters
mmBtu	One Million British Thermal Units

MMcf/day	million cubic feet per day
MMscf/day	million standard cubic feet per day
MMV	Measurement, Monitoring and Verification Techniques
MOA	Memorandum of Agreement
MOU	Memorandum of Understanding
mph	Miles Per Hour
MPO	Metropolitan Planning Organization
MSI	Mountain Studies Institute
MW	Megawatt
N	Nitrogen
N2	Nitrogen gas
N2O	Nitrous Oxide
N2O3	Nitrogen Oxide
N2O5	Nitric Pentoxide
NA	Not Applicable
Na	Sodium
NAAQS	National Ambient Air Quality Standard
NADP	National Atmospheric Deposition Program
NEG	Net Excess Generation
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NG	Natural Gas
NGCC	Natural Gas Combined Cycle
NGL	natural gas liquids
NH3	Ammonia
NI	no information
NM	New Mexico
NMED-AQB	New Mexico Environment Department-Air Quality Bureau
NMEMNRD	New Mexico Energy, Minerals and Natural Resources Department
NMHC	Non-Methane Hydrocarbon
NMOC	Non-Methane Organic Compounds
NMOCD	New Mexico Oil Conservation Division
NMOG	Non-Methane Organic Gas
NMOGA	New Mexico Oil and Gas Association
NMRPC	New Mexico Public Regulation Commission
NMUSA	New Mexico Utility Shareholders Alliance
NNEPA	Navajo Nation Environmental Protection Agency
No.	Number
NO	Nitric Oxide
NO2	Nitrogen Dioxide
NO3	Nitrate
NOx	Nitrogen Oxides
NOx/mmBtu	Nitrogen Oxides per million British Thermal Units
NOAA	National Oceanic & Atmospheric Administration
NP	National Park
NPS	National Park Service
NPV	Net Present Value
NRDC	Natural Resources Defense Council
NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standards
NSR	New Source Review
NTN	National Trends Network
NW	Northwest
NWS	National Weather Service
NYCRR	New York Codes, Rules and Regulations
O&M	Operation and Maintenance
O2	Oxygen

O3	Ozone
OCD	Oil Conservation Division
OCV	Open Crankcase Ventilation
OECA	Office of Enforcement and Compliance Assurance
OH	Hydroxide
ONG	Onshore Natural Gas
OP-FTIR	Open-Path Fourier Transform Infrared
Oz	Ounce
PAH(s)	Polycyclic Aromatic Hydrocarbon
PC	Pulverized Coal
P/H	Power to Heat Ratio
pH	Acidity Measurement Unit
PLC	Programmable Logic Controller
PM	Particulate Matter
PM_{10}	Particulate Matter (effective diameter < 10 micrograms)
$PM_{2.5}$	Fine Particulate Matter (effective diameter < 2.5 micrograms)
POWID	Power Industry Division
ppb	parts per billion
ppm	parts per million
PRO	Partner Reported Opportunities
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PSNM	Public Service of New Mexico
PV	Photovoltaic
QA	Quality Assurance
QC	Quality Control
R&D	Research and Development
RACM	Reasonably Available Control Measures
RACT	Reasonably Available Control Technology
RAWS	Remote Automated Weather Stations
RC&D	Resource Conservation and Development
RE	Renewable Energy
REC(s)	Renewable Energy Credit
RH	Relative Humidity
RIA	Regulatory Impact Analyses
RICE	Reciprocating Internal Combustion Engine
RMP	Resource Management Plan
RMPPA	Resource Management Plan Planning Area
ROD	Record of Decision
ROG	Reactive Organic Gas
ROI	Return on Investment
RPM	Revolutions Per Minute
RPS	Renewable Portfolio Standards
RRC	Rebecca Reynolds Consulting
RVP	Reid Vapor Pressure
S	Sulfur
SAR	Specific Absorption Rate
scfh	standard cubic feet per hour of gas flow
SC	Supercritical
SCPC	Supercritical Pulverized Coal
SCR	Selective Catalytic Reduction
SEP(s)	Supplemental Energy Payment
SI	Spark-Ignition Engine
SIP	State Implementation Plan

SJ	San Juan
SJGS	San Juan Generating Station
SLAMS	State/Local Air Monitoring Stations
SNCR	Selective Non-Catalytic Reduction
SO2	Sulfur Dioxide
SO2/mmBtu	Sulfur Dioxide/one million British Thermal Units
SOTA	State of the Art
SOx	Sulfur Oxides
SPMS	Special Purpose Monitoring Stations
sq mi	Square Miles
SRI	Southern Research Institute
SRP	Salt River Project Agricultural Improvement and Power District
SUIT	Southern Ute Indian Tribe
SW	Southwest
SWD	Salt Water Disposal Well
SWEEP	Southwest Energy Efficiency Project
TAG	Technical Assessment Guide
TBD	To Be Determined
TDLAS	Tunable Diode Laser Absorption Spectroscopy
TDS	Total Dissolved Solids
TEG	Triethylene Glycol
TF	Task Force
THC	Total Hydrocarbons
TPH	Total Petroleum Hydrocarbons
tpy	tons per year
TSD	technical support document
U.S.C.	United States Code
ULSD	Ultra Low Sulfur Diesel
US	United States
USC	Ultra Supercritical Coal
USCPC	Ultra-Supercritical Pulverized Coal
USDA	U.S. Department of Agriculture
USDI	U.S. Department of the Interior
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
UST	Underground Storage Tank
UT	Utah
VISTAS	Voluntary Innovative Strategies for Today's Air Standards Program
VLUA	Vallecito Land Use Association
VMT	Vehicle Miles Traveled
VOC(s)	Volatile Organic Compounds
VRM	Visual Resource Management
VRP	Visibility Reducing Particles
VRU	Vapor Recovery Unit
vs.	Versus
W	West
W/m2	Watts per square meter
W/O	without
WDEQ	Wyoming Department of Environmental Quality
WESTAR	Western States Air Resource Council
WRAP	Western Regional Air Partnership

Definitions

Definitions

3-way catalyst: A catalyst containing both reduction and oxidation catalyst materials that converts Oxides of Nitrogen (NO_X), Carbon Monoxide (CO), and Non-Methane Hydrocarbons (NMHCs) to Nitrogen (N_2), Carbon Dioxide (CO_2), and water H_2O.

AP-42: An U.S. EPA compendium of emission factors for different source types. An emission factor is a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant. These factors are usually expressed as the weight of pollutant divided by a unit weight, volume, distance, or duration of the activity emitting the pollutant (e. g., kilograms of particulate emitted per megagram of coal burned). For additional information, see EPA's website at http://www.epa.gov/ttn/chief/ap42/.

Absorption: The process by which the energy of a photon is taken up by another entity.

Acid Deposition: A comprehensive term for the various ways acidic compounds precipitate from the atmosphere and deposit onto surfaces. It can include: 1) wet deposition by means of acid rain, fog, and snow; and 2) dry deposition of acidic particles (aerosols).

Acid Rain: Rain which is especially acidic (pH <5.2). Principal components of acid rain typically include nitric and sulfuric acid. These may be formed by the combination of nitrogen and sulfur oxides with water vapor in the atmosphere.

Acid Rain Program: The overall goal of the Acid Rain Program is to achieve significant environmental and public health benefits through reductions in emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx)—the primary causes of acid rain. To achieve this goal at the lowest cost to society, the program employs both traditional and innovative, market-based approaches for controlling air pollution. In addition, the program encourages energy efficiency and pollution prevention.

Activated Carbon Injection (ACI) Technology: In ACI technology, powdered activated carbon (PAC) sorbent is injected into the flue gas at a location in the duct preceding the particulate matter (PM) control device, which usually is an electrostatic precipitator or a fabric filter. The PAC sorbent binds with the mercury in the flue gas in the duct and in the PM control device. Subsequently, the mercury-containing PAC is captured in the PM control device.
Carbon Capture and Sequestration (CCS): Carbon capture and storage is an approach to mitigating climate change by capturing carbon dioxide (CO2) from large point sources such as power plants and subsequently storing it away safely instead of releasing it into the atmosphere. Technology for capturing of CO2 is already commercially available for large CO2 emitters, such as power plants. Storage of CO2, on the other hand, is a relatively untried concept and as yet (2007) no power plant operates with a full carbon capture and storage system. Currently, the United States government has approved the construction of the world's first CCS power plant, FutureGen, while BP has indicated that it intends to develop a 350 MW carbon capture and storage plant in Scotland, in which the carbon from a natural gas fired generator plant will be stripped out and pumped into the Miller field in the North Sea.

Add-On Control Device: An air pollution control device such as carbon absorber or incinerator that reduces the pollution in exhaust gas. The control device usually does not affect the process being controlled and thus is "add-on" technology, as opposed to a scheme to control pollution through altering the basic process itself. See also pollution prevention.

Adsorber: An emissions control device that removes volatile organic compounds (VOCs) from a gas stream as a result of the gas attaching (adsorbing) onto a solid matrix such as activated carbon.

Adsorption (Physical and Chemical): capability of all solid substances to attract to their surfaces molecules of gases or solutions with which they are in contact. Solids that are used to adsorb gases or dissolved substances are called adsorbents; the adsorbed molecules are usually referred to collectively as the adsorbate. An example of an excellent adsorbent is the charcoal used in gas mask.

Adverse Health Effect: A health effect from exposure to air contaminants that may range from relatively mild temporary conditions, such as eye or throat irritation, shortness of breath, or headaches to permanent and serious conditions, such as birth defects, cancer or damage to lungs, nerves, liver, heart, or other organs.

Aerosol: Particles of solid or liquid matter that can remain suspended in air from a few minutes to many months depending on the particle size and weight.

Afterburner: An air pollution abatement device that removes undesirable organic gases through incineration.

Agricultural Burning: The intentional use of fire for vegetation management in areas such as agricultural fields, orchards, rangelands, and forests.

Air: So called "pure" air is a mixture of gases containing about 78 percent nitrogen; 21 percent oxygen; less than 1 percent of carbon dioxide, argon, and other gases; and varying amounts of water vapor. See also ambient air.

Air Monitoring: Sampling for and measuring of pollutants present in the atmosphere.

Air Pollutants: Amounts of foreign and/or natural substances occurring in the atmosphere that may result in adverse effects to humans, animals, vegetation, and/or materials. (See also air pollution.)

Air Pollution: Degradation of air quality resulting from unwanted chemicals or other materials occurring in the air. (See also air pollutants.)

Air Quality Index (AQI): A numerical index used for reporting severity of air pollution levels to the public. The AQI incorporates five criteria pollutants -- ozone, particulate matter, carbon monoxide, sulfur dioxide, and nitrogen dioxide -- into a single index. The new index also incorporates the 8-hour ozone standard and the 24-hour $PM_{2.5}$ standard into the index calculation. AQI levels range from 0 (Good air quality) to 500 (Hazardous air quality). The higher the index, the higher the level of pollutants and the greater the likelihood of health effects. The AQI incorporates an additional index category -- unhealthy for sensitive groups -- that ranges from 101 to 150. In addition, the AQI comes with more detailed cautions.

Air Quality Model: A mathematical relationship between emissions and air quality which simulates on a computer the transport, dispersion, and transformation of compounds emitted into the air.

Air Quality Standard (AQS): The prescribed level of a pollutant in the outside air that should not be exceeded during a specific time period to protect public health. Established by both federal and state governments. (See also ambient air quality standards.)

Air separation membranes: Change the proportion of nitrogen to oxygen in air. A membrane can be optimized to either enrich the oxygen content or to enrich the nitrogen content.

Airshed: Denotes a geographical area that shares the same air because of topography, meteorology, and climate.

Air to Fuel Ratio Controller (AFRC): Device using a closed loop control based on the readings of an exhaust gas oxygen sensor to determine the air/fuel ratio.

Air Toxics: A generic term referring to a harmful chemical or group of chemicals in the air. Substances that are especially harmful to health, such as those considered under U.S. EPA's hazardous air pollutant program, are considered to be air toxics. Technically, any compound that is in the air and has the potential to produce adverse health effects is an air toxic.

Alcohol Fuels: Alcohol can be blended with gasoline for use as transportation fuel. It may be produced from a wide variety of organic feedstock. The common alcohol fuels are methanol and ethanol. Methanol may be produced from coal, natural gas, wood and organic waste. Ethanol is commonly made from agricultural plants, primarily corn, containing sugar.

Alkane: Chemical compounds that consist only of the elements carbon (C) and hydrogen (H) (i.e. hydrocarbons), where each of these atoms are linked together exclusively by single bonds.

Alternative Fuels: Fuels such as methanol, ethanol, natural gas, and liquid petroleum gas that are cleaner burning and help to meet mobile and stationary emission standards. These fuels may be used in place of less clean fuels for powering motor vehicles.

Ambient Air: The air occurring at a particular time and place outside of structures. Often used interchangeably with "outdoor air." (See also air.)

Ambient Air Quality Standards (AAQS): Health- and welfare-based standards for outdoor air which identify the maximum acceptable average concentrations of air pollutants during a specified period of time. (See also NAAQS and Criteria Air Pollutant.)

American Society for Testing and Materials (ASTM): A nonprofit organization that provides a forum for producers, consumers, and representatives of government and industry, to write laboratory test standards for materials, products, systems, and services. ASTM publishes standard test methods, specifications, practices, guides, classifications, and terminology.

Amines: Amines are organic compounds that contain nitrogen as the key atom. Structurally, amines resemble ammonia. The advantage of an amine CO_2 removal system is that it has a lower capital cost than any of the current physical solvent processes. The disadvantage is that an amine system uses large amounts of steam heat for solvent regeneration and energy to re-cool the amine, making it a less energy efficient process**.**

Ammonia (NH_3): A pungent colorless gaseous compound of nitrogen and hydrogen that is very soluble in water and can easily be condensed into a liquid by cold and pressure. Ammonia reacts with NOx to form ammonium nitrate -- a major $PM_{2.5}$ component in the Western United States.

Ammonia slip: Ammonia emissions from SCR systems.

Area Sources: Those sources for which a methodology is used to estimate emissions. This can include area-wide, mobile and natural sources, and also groups of stationary sources (such as dry cleaners and gas stations). Sources which are not reported as individual point sources are included as area sources. The federal air toxics program defines a source that emits less than 10 tons per year of a single hazardous air pollutant (HAP) or 25 tons per year of all HAPs as an area source.

Aromatic compounds: An organic chemical compound that contains aromatic rings (arenes) like benzene, pyridine, or indole and possessing an aroma, fragrance, flavor, smell, or odor

Asthma: A chronic inflammatory disorder of the lungs characterized by wheezing, breathlessness, chest tightness, and cough.

Atmosphere: The gaseous mass or envelope of air surrounding the Earth. From ground-level up, the atmosphere is further subdivided into the troposphere, stratosphere, mesosphere, and the thermosphere.

Attainment Area: A geographical area identified to have air quality as good as, or better than, the national ambient air quality standards (NAAQS). An area may be an attainment area for one pollutant and a nonattainment area for others.

Baghouse: An air pollution control device that traps particulates by forcing gas streams through large permeable bags usually made of glass fibers.

Banking: A provision used in emissions trading programs that allows a facility to accumulate credits for reducing emissions beyond regulatory limits (emission reduction credits) and then use or sell those credits at a later date.

Baseline: A starting point or condition against which future changes are measured. For air quality emissions, the known emissions in a given year that future emissions can be measured against.

Benzene, Toluene, Ethyl Benzene, Xylene (BTEX): Group of volatile organic compounds (VOCs) found in petroleum hydrocarbons, such as gasoline, and other common environmental contaminants.

Best Available Control Measure (BACM): A term used to describe the "best" measures (according to U.S. EPA guidance) for controlling small or dispersed sources of particulate matter and other emissions from sources such as roadway dust, woodstoves, and open burning.

Best Available Control Technology (BACT): The most up-to-date methods, systems, techniques, and production processes available to achieve the greatest feasible emission reductions for given regulated air pollutants and processes. BACT is a requirement of NSR (New Source Review) and PSD (Prevention of Significant Deterioration).

Best Available Retrofit Technology (BART): An air emission limitation that applies to existing sources and is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source. (See also Best Available Control Technology.)

Bioenergy: Useful, renewable energy produced from organic matter, which may either be used directly as a fuel or processed into liquids and gases.

Biofuels: Liquid fuels and blending components produced from biomass (plant) feedstocks, used primarily for transportation.

Biogenic Source: Biological sources such as plants and animals that emit air pollutants such as volatile organic compounds. Examples of biogenic sources include animal management operations, and oak and pine tree forests. (See also natural sources.)

Biomass: Organic nonfossil matter of a biological origin available on a renewable basis. Biomass includes forest and mill residues, agricultural crops and wastes, wood and wood wastes, animal wastes, livestock operation residues, aquatic plants, fast-growing trees and plants, and municipal and industrial wastes.

Boiler: A device for generating steam for power, processing, or heating purposes or for producing hot water for heating purposes or hot water supply. A device where heat converts water to steam.

Carbon (CO2) Capture and Storage: CO2 capture and storage involves capturing the CO2 arising from the combustion of fossil fuels, as in power generation, or from the preparation of fossil fuels, as in natural-gas processing. Capturing CO2 involves separating the CO2 from some other gases. For example in the exhaust gas of a power plant other gases would include nitrogen and water vapor. The CO2 must then be transported to a storage site where it will be stored away from the atmosphere for a long period of time. In order to have a significant effect on atmospheric concentrations of CO2, storage reservoirs would have to be large relative to annual emissions. (IPCC, 2001). Sometimes referred to as sequestration.

Carbon Dioxide (CO_2): A colorless, odorless gas that occurs naturally in the Earth's atmosphere. Significant quantities are also emitted into the air by fossil fuel combustion.

Carbon mass balance: An accounting of material entering and leaving a system.

Carbon Monoxide (CO): A colorless, odorless gas resulting from the incomplete combustion of hydrocarbon fuels. CO interferes with the blood's ability to carry oxygen to the body's tissues and results in numerous adverse health effects. CO is a criteria air pollutant.

Carcinogen: A cancer-causing substance. (See also cancer.)

CAS Registry Number: The Chemical Abstracts Service Registry Number (CAS) is a numeric designation assigned by the American Chemical Society's Chemical Abstract Service and uniquely identifies a specific compound. This entry allows one to conclusively identify a material regardless of the name or naming system used.

Catalyst: A substance that can increase or decrease the rate of a chemical reaction between the other chemical species without being consumed in the process.

Catalyst Deactivation: Poisoning is a primary factor in deactivation, with blockage and physical destruction of equal importance to catalyst life. When the surface or pores of the catalyst are blocked, flue gas/NOx cannot contact the catalyst.

Catalytic converter: The mechanism by which the catalyst will either oxidize (oxidation catalyst) a CO or fuel molecule or reduce (reduction catalyst) a NO_X molecule.

Cation: A positively-charged ion, which has fewer electrons than protons. An ion is an atom or group of atoms which have lost or gained one or more electrons, making them negatively or positively charged.

Cell Burner: Cell burner boiler means a wall-fired boiler that utilizes two or three circular burners combined into a single vertically oriented assembly that results in a compact, intense flame. Cell burner boilers have closely spaced clusters of two or three burners (i.e., cells) that together result in a single flame. In addition, the boilers are, like many wall-fired boilers, relatively compactly designed with small furnaces.

Chromatography: A set of laboratory techniques for separation of mixtures. One such procedure includes passing a mixture dissolved in a "mobile phase" through a stationary phase, which separates the analyte to be measured from other molecules in the mixture and allows it to be isolated.

Chronic Exposure: Long-term exposure, usually lasting one year to a lifetime.

Chronic Health Effect: A health effect that occurs over a relatively long period of time (e.g., months or years). (See also acute health effect.)

Class I Area: Under the Clean Air Act, a Class I area is one in which visibility is protected more stringently than under the national ambient air quality standards; includes national parks, wilderness area, monuments and other areas of special national and cultural significance.

Clean Air Act (CAA): A federal law passed in 1970 and amended in 1974, 1977 and 1990 which forms the basis for the national air pollution control effort. Basic elements of the act include national ambient air quality standards for major air pollutants, mobile and stationary control measures, air toxics standards, acid rain control measures, and enforcement provisions.

Clean Air Mercury Rule: On March 15, 2005, EPA issued the Clean Air Mercury Rule to permanently cap and reduce mercury emissions from coal-fired power plants for the first time ever. This rule makes the United States the first country in the world to regulate mercury emissions from utilities.

Cleaner-Burning Gasoline: Gasoline fuel that results in reduced emissions of carbon monoxide, nitrogen oxides, reactive organic gases, and particulate matter, in addition to toxic substances such as benzene and 1,3-butadiene.

Coal bed methane (CBM): Methane found in coal seams.

Code of Federal Regulations (CFR): The codification of the general and permanent rules published in the Federal Register by the executive departments and agencies of the Federal Government pursuant to authority derived from the Clean Air, Water, and other environmental acts.

Cogeneration: See combined heat and power.

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. Such designs increase the efficiency of the electric generating unit.

Combined Heat and Power (CHP) Plant: A plant designed to produce both heat and electricity from a single heat source. Note: This term is being used in place of the term "cogenerator" that was used by EIA in the past. CHP better describes the facilities because some of the plants included do not produce heat and power in a sequential fashion and, as a result, do not meet the legal definition of cogeneration specified in the Public Utility Regulatory Policies Act (PURPA).

Combustion: The act or instance of burning some type of fuel such as gasoline to produce energy. Combustion is typically the process that powers automobile engines, oil and gas-field engines, and power plant generators.

Compressed natural gas (CNG): A substitute for gasoline (petrol) or diesel fuel, made by compressing methane extracted from natural gas.

Concentrator: A reflective or refractive device that focuses incident insolation onto an area smaller than the reflective or refractive surface, resulting in increased insolation at the point of focus.
Conventional hydroelectric (hydropower) plant: A plant in which all of the power is produced from natural streamflow as regulated by available storage.

Condensate tank: Tank for storing condensate from oil and gas activity.

Condensate Tank Battery: Comprised of a single storage tank or a group of storage tanks with a design capacity less than or equal to 10,000 barrels per tank, used for the storage of condensate and located at an exploration and production facility.

Consent Decree: When a court case has been filed, the parties can resolve the case short of having a trial by entering into a joint agreement or by consenting to a judgment.

Continuous Emission Monitor (CEM): A type of air emission monitoring system installed to operate continuously inside of a smokestack or other emission source.

Continuous Sampling Device: An air analyzer that measures air quality components continuously. (See also Integrated Sampling Device.)

Control Techniques Guidelines (CTG): Guidance documents issued by U.S. EPA that define reasonably available control technology (RACT) to be applied to existing facilities that emit excessive quantities of air pollutants; they contain information both on the economic and technological feasibility of available techniques.

Cost-Effectiveness: The cost of an emission control measure assessed in terms of dollars-per-pound, or dollars-per-ton, of air emissions reduced.

Criteria Air Pollutant: An air pollutant for which acceptable levels of exposure can be determined and for which an ambient air quality standard has been set. Examples include: ozone, carbon monoxide, nitrogen dioxide, sulfur dioxide, and PM_{10} and $PM_{2.5}$. The term "criteria air pollutants" derives from the requirement that the U.S. EPA must describe the characteristics and potential health and welfare effects of these pollutants. The U.S. EPA periodically reviews new scientific data and may propose revisions to the standards as a result.

Cryogenic: production of very low temperatures and the behavior of materials at those temperatures below -150C.

Cyclone: An air pollution control device that removes larger particles -- generally greater than one micron -- from an air stream through centrifugal force.

Deciview: A measurement of visibility. One deciview represents the minimal perceptible change in visibility to the human eye.

Desiccant dehydrator: Device that uses moisture-absorbing salts to remove water from natural gas. In general, there are only minor air emissions from desiccant systems.

Diesel Engine: A type of internal combustion engine that uses low-volatility petroleum fuel and fuel injectors and initiates combustion using compression ignition (as opposed to spark ignition that is used with gasoline engines).

Diesel fuel emulsion: Emulsion of diesel and other fuel intended to reduce peak engine combustion temperatures and increase fuel atomization and combustion efficiency.

Diesel oxidation catalyst (DOC): Device that uses a chemical process to break down pollutants in the exhaust stream into less harmful components. Diesel oxidation catalysts can reduce emissions of particulate matter (PM) by 20% and hydrocarbons (HC) by 50% and carbon monoxide (CO) by approximately 40%.

Diesel particulate filter: Filter that collects or traps particulate matter (PM) in the exhaust.

Diffraction: Diffraction refers to various phenomena associated with wave propagation, such as the bending, spreading and interference of waves such as visible light.

Dispersion Model: See air quality model above.

Distributed Generation (Distributed Energy Resources): Refers to electricity provided by small, modular power generators (typically ranging in capacity from a few kilowatts to 50 megawatts) located at or near customer demand.

Dose: The amount of a pollutant that is absorbed. A level of exposure which is a function of a pollutant's concentration, the length of time a subject is exposed, and the amount of the pollutant that is absorbed. The concentration of the pollutant and the length of time that the subject is exposed to that pollutant determine dose.

Dose-Response: The relationship between the dose of a pollutant and the response (or effect) it produces on a biological system.

Drill rig: General term used to describe a wide variety of machines that create holes (usually called boreholes) and/or shafts in the ground, or to install wells.

Dry-bottom, Wall-fired: Dry bottom means the boiler has a furnace bottom temperature below the ash melting point and the bottom ash is removed as a solid. Wall-fired boiler means a boiler that has pulverized coal burners arranged on the walls of the furnace. The burners have discrete, individual flames that extend perpendicularly into the furnace area.

Dry Cooled Coal-Fired: Dry cooling operates without evaporation by passing the steam from the turbines through a set of finned pipes immediately beside the turbine and cooling the water by having large volumes of air driven by fans to condense the steam in the pipes.

Dust: Solid particulate matter that can become airborne.

Ecosystem: A self-sustaining association of plants, animals, and the physical environment in which they live.

Electric Generating Unit (EGU) – Clean Air Interstate Rule definition:
(a) Except as provided in paragraph (b) of this definition, a stationary, fossil-fuel-fired boiler or stationary, fossil fuel fired combustion turbine serving at any time, since the start-up of a unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.
(b) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of

the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (a) of this definition starting on the day on which the unit first no longer qualifies as a cogeneration unit.

Electric Utility: A corporation, person, agency, authority, or other legal entity or instrumentality aligned with distribution facilities for delivery of electric energy for use primarily by the public. Included are investor-owned electric utilities, municipal and State utilities, Federal electric utilities, and rural electric cooperatives. A few entities that are tariff based and corporately aligned with companies that own distribution facilities are also included.

Electrostatic Precipitator (ESP): An air pollution control device that removes particulate matter from an air stream by imparting an electrical charge to the particles for mechanical collection at an electrode.

Emission Factor: For stationary sources, the relationship between the amount of pollution produced and the amount of raw material processed or burned. For mobile sources, the relationship between the amount of pollution produced and the number of vehicle miles traveled. By using the emission factor of a pollutant and specific data regarding quantities of materials used by a given source, it is possible to compute emissions for the source. This approach is used in preparing an emissions inventory.

Emission Inventory: An estimate of the amount of pollutants emitted into the atmosphere from major mobile, stationary, area-wide, and natural source categories over a specific period of time such as a day or a year.

Emission Rate: The weight of a pollutant emitted per unit of time (e.g., tons / year).

Emission Standard: The maximum amount of a pollutant that is allowed to be discharged from a polluting source such as an automobile or smoke stack.

Emission trading system (ETS): Program wherein the governing authority (e.g., agency) issues a limited number of allocations in the form of certificates consistent with the desired or targeted level of emissions in an identified region or area. The sources of a particular air pollutant (e.g., NOx) are allotted certificates to release a specified number of tons of the pollutant. The certificate owners may choose either to continue to release the pollutant at current levels and use the certificates or to reduce their emissions and sell the certificates.

Enardo valve: Brand name for a pressure relief valve installed on condensate and other oil storage tanks to control evaporation and fugitive emission losses that result from flammable and hazardous petroleum vapor-producing products.

Energy Content: The amount of energy available for doing work. For example, the amount of energy in fuel available for powering a motor vehicle.

Energy Crops: Crops grown specifically for their fuel value. These include food crops such as corn and sugarcane, and nonfood crops such as poplar trees and switchgrass. Currently, two energy crops are under development: short - rotation woody crops, which are fast - growing hardwood trees harvested in five to eight years, and herbaceous energy crops, such as perennial grasses, which are harvested annually after taking two to three years to reach full productivity.

Energy Efficiency: Energy efficiency refers to products or systems using less energy to do the same or better job than conventional products or systems. Energy efficiency saves energy, saves money on utility bills, and helps protect the environment by reducing the amount of electricity that needs to be generated. When buying or replacing products or appliances for your home, look for the ENERGY STAR® label — the national symbol for energy efficiency. For more information on ENERGY STAR® labeled products, visit the ENERGY STAR® Web site.

Enhanced Gas Recovery and/or Enhanced Coal Bed Methane Recovery: To enhance coal bed methane recovery factors and production rates as a result of CO2 injection.
Burlington Resources has successfully injected CO2 into relatively high permeability coalbeds in the San Juan basin in the USA for several years. They are stimulating coalbed methane production and recovery. The injected CO2 is

adsorbed into the coal matrix and remains in the ground after completion of gas production. However, further testing and demonstration are needed to apply this process to low permeability reservoirs.

Enhanced Oil Recovery: Using CO_2 injection to enhance production from oil reservoirs.

Environmental Justice: The fair treatment of people of all races and incomes with respect to development, implementation, and enforcement of environmental laws, regulations, and policies.

EPA's Natural Gas STAR Program: The Natural Gas STAR Program is a flexible, voluntary partnership between U.S. EPA and the oil and natural gas industry. Through the program, U.S. EPA works with companies that produce, process, and transmit and distribute natural gas to identify and promote the implementation of cost-effective technologies and practices to reduce emissions of methane, a potent greenhouse gas.

Ethanol (also known as Ethyl Alcohol or Grain Alcohol, CH3-CH2OH): A clear, colorless flammable oxygenated hydrocarbon with a boiling point of 173.5 degrees Fahrenheit in the anhydrous state. However it readily forms a binary azetrope with water, with a boiling point of 172.67 degrees Fahrenheit at a composition of 95.57 percent by weight ethanol. It is used in the United States as a gasoline octane enhancer and oxygenate (maximum 10 percent concentration). Ethanol can be used in higher concentrations (E85) in vehicles designed for its use. Ethanol is typically produced chemically from ethylene, or biologically from fermentation of various sugars from carbohydrates found in agricultural crops and cellulosic residues from crops or wood. The lower heating value, equal to 76,000 Btu per gallon, is assumed for estimates in this report.

Evacuated Tube: In a solar thermal collector, an absorber tube, which is contained in an evacuated glass cylinder, through which collector fluids flows.

Evaporative Emissions: Emissions from evaporating gasoline, which can occur during vehicle refueling, vehicle operation, and even when the vehicle is parked. Evaporative emissions can account for two-thirds of the hydrocarbon emissions from gasoline-fueled vehicles on hot summer days.

Exhaust Gas Recirculation (EGR): An emission control method that involves recirculating exhaust gases from an engine back into the intake and combustion chambers. This lowers combustion temperatures and reduces NOx. (See also nitrogen oxides.)

Exceedance: A measured level of an air pollutant higher than the national or state ambient air quality standards. (See also NAAQS.)

Federal Implementation Plan (FIP): In the absence of an approved State Implementation Plan (SIP), a plan prepared by the U.S. EPA which provides measures that areas must take to meet the requirements of the Federal Clean Air Act.

Feedstock: The raw material that is required for some industrial process.

Flaring: Technique of igniting hydrocarbon gases to convert natural gas constituents (hydrocarbons, including BTEX and other Hazardous Air Pollutants) into less hazardous and atmospherically reactive compounds.

Flash emissions: Emissions resulting by a reduction in pressure and/or temperature when hydrocarbon liquids are dumped into the storage tank from the production separator.

Flow through filters (FTF): Filters for capture or oxidize particles, using a variety of media and regeneration strategies. The filter media can be either wire mesh or pertubated path metal foil.

Flue gas: Exhaust gases following combustion.

Fly Ash: Air-borne solid particles that result from the burning of coal and other solid fuel.

Fossil Fuels: Fuels such as coal, oil, and natural gas; so-called because they are the remains of ancient plant and animal life.

Fugitive Dust: Dust particles that are introduced into the air through certain activities such as soil cultivation, or vehicles operating on open fields or dirt roadways. A subset of fugitive emissions.

Fugitive Emissions: Emissions not caught by a capture system which are often due to equipment leaks, evaporative processes and windblown disturbances.

Furnace: A combustion chamber; an enclosed structure in which fuel is burned to heat air or material.

FutureGen: FutureGen is a project of the US government to build a near zero-emissions coal-fueled power plant that intends to produce hydrogen and electricity while using carbon capture and storage.

Gas Turbine: An engine that uses a compressor to draw air into the engine and compress it. Fuel is added to the air and combusted in a combustor. Hot combustion gases exiting the engine turn a turbine which also turns the compressor. The engine's power output can be delivered from the compressor or turbine side of the engine.

Gasifier: A device for converting solid fuel into gaseous fuel.

Generation (Electricity): The process of producing electric energy from other forms of energy; also, the amount of electric energy produced, expressed in watthours (Wh).

Global Warming: An increase in the temperature of the Earth's troposphere. Global warming has occurred in the past as a result of natural influences, but the term is most often used to refer to the warming predicted by computer models to occur as a result of increased emissions of greenhouse gases.

GLYCALC: A software program for estimating air emissions from glycol units using triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).

Glycol dehydrator: Any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water from the natural gas stream.

Green Power: Electricity that is generated from renewable energy sources is often referred to as "green power." Green power products can include electricity generated exclusively from renewable resources or, more frequently, electricity produced from a combination of fossil and renewable resources. Also known as "blended" products, these products typically have lower prices than 100 percent renewable products. Customers who take advantage of these options usually pay a premium for having some or all of their electricity produced from renewable resources. To find out more about green power, visit EPA's Green Power Partnership Web site.

Greenhouse Effect: The warming effect of the Earth's atmosphere. Light energy from the sun which passes through the Earth's atmosphere is absorbed by the Earth's surface and re-radiated into the atmosphere as heat energy. The heat energy is then trapped by the atmosphere, creating a situation similar to that which occurs in a car with its windows rolled up. A number of scientists believe that the emission of CO_2 and other gases into the atmosphere may increase the greenhouse effect and contribute to global warming.

Greenhouse Gases: Atmospheric gases such as carbon dioxide, methane, chlorofluorocarbons, nitrous oxide, ozone, and water vapor that slow the passage of re-radiated heat through the Earth's atmosphere.

Gypsum: Gypsum is one of the most widely used minerals in the world. Most gypsum in the United States is used to make wallboard for homes, offices, and commercial buildings; a typical new American home contains more than seven metric tons of gypsum alone. Moreover, gypsum is used worldwide in concrete for highways, bridges, buildings, and many other structures that are part of our everyday life. Gypsum also is used extensively as a soil conditioner on large tracts of land in suburban areas, as well as in agricultural regions.

Hazardous Air Pollutant (HAP): An air pollutant listed under section 112 (b) of the federal Clean Air Act as particularly hazardous to health. Emission sources of hazardous air pollutants are identified by U.S. EPA, and emission standards are set accordingly.

Haze (Hazy): A phenomenon that results in reduced visibility due to the scattering of light caused by aerosols. Haze is caused in large part by man-made air pollutants.

Health-Based Standard (Primary Standard): A dosage of air pollution scientifically determined to protect against human health effects such as asthma, emphysema, and cancer.

Heat Recovery Steam Generator (HRSG): Recovers waste heat exhaust from a combustion turbine and generates steam

"Hot Spot": (See toxic hot spot.)

Hydrated Lime Injection: Calcium hydroxide, also known as slaked lime, is a chemical compound with the chemical formula Ca(OH)2. It is a colorless crystal or white powder, and is obtained when calcium oxide (called lime or quicklime) is slaked with water. It can also be precipitated by mixing an aqueous solution of calcium chloride and an aqueous solution of sodium hydroxide. A traditional name for calcium hydroxide is slaked lime, or hydrated lime.
Hydrated lime may be injected into the upper regions of a furnace where high temperatures are conducive to driving the reaction between the calcium and SO2 to achieve up to 70% SO2 removal.

Hydrocarbons: Compounds containing various combinations of hydrogen and carbon atoms. They may be emitted into the air by natural sources (e.g., trees) and as a result of fossil and vegetative fuel combustion, fuel volatilization, and solvent use. Hydrocarbons are a major contributor to smog.

Hydrogen Sulfide (H_2S): A colorless, flammable, poisonous compound having a characteristic rotten-egg odor. It is used in industrial processes and may be emitted into the air.

Incentives: Subsidies and other Government actions where the Governments's financial assistance is indirect.

Incineration: The act of burning a material to ashes.

Indirect emissions: *See* Indirect Source.

Indirect Source: Any facility, building, structure, or installation, or combination thereof, which generates or attracts mobile source activity that results in emissions of any pollutant (or precursor) for which there is a state ambient air quality standard. Examples of indirect sources include employment sites, shopping centers, sports facilities, housing developments, airports, commercial and industrial development, and parking lots and garages.

Industrial Source: Any of a large number of sources -- such as manufacturing operations, oil and gas refineries, food processing plants, and energy generating facilities -- that emit substances into the atmosphere.

Inert Gas: A gas that does not react with the substances coming in contact with it.

Inert gas blanket: "Blanket" of inert (chemically non-reactive) gas that fills the space above the condensate/crude oil to minimize volatilization and vapor loss.

Injection wells: Well in which fluids are injected rather than produced, the primary objective typically being to maintain reservoir pressure. Two common types of injection gas and water. Separated gas from production wells or possibly imported gas may be reinjected into the upper gas section of the reservoir to maintain pressure.

Inspection and Maintenance (I&M) Program: A motor vehicle inspection program. The purpose of the I&M is to reduce emissions by assuring that cars are running properly. It is designed to identify vehicles in need of maintenance and to assure the effectiveness of their emission control systems on a biennial basis.

Integrated Sampling Device: An air sampling device that allows estimation of air quality components over a period of time through laboratory analysis of the sampler's medium.

Internal Combustion Engine: An engine in which both the heat energy and the ensuing mechanical energy are produced inside the engine. Includes gas turbines, spark ignition gas, and compression ignition diesel engines.

Inversion: A layer of warm air in the atmosphere that prevents the rise of cooling air and traps pollutants beneath it.

Kilowatt (kW): One thousand watts of electricity (See Watt).

Kilowatthour (kWh): One thousand watthours.

Kimray pump: Brand name of automated glycol pump used to circulate glycol in dehydrators.

Laser ignition: Ignition sequence replacing the conventional spark plugs with a laser beam that is focused to a point in the combustion chamber. There, the focused, coherent light ionizes the fuel-air mixture to initiate combustion.

Lead: A gray-white metal that is soft, malleable, ductile, and resistant to corrosion. Sources of lead resulting in concentrations in the air include industrial sources and crustal weathering of soils followed by fugitive dust emissions. Health effects from exposure to lead include brain and kidney damage and learning disabilities. Lead is the only substance which is currently listed as both a criteria air pollutant and a toxic air contaminant.

Leadership in Energy Efficiency and Design certification (LEED): The Leadership in Energy and Environmental Design (LEED) Green Building Rating System™ is the nationally accepted benchmark for the design, construction, and operation of high performance green buildings. LEED gives building owners and operators the tools they need to have an immediate and measurable impact on their buildings' performance. LEED promotes a whole-building approach to sustainability by recognizing performance in five key areas of human and environmental health: sustainable site development, water savings, energy efficiency, materials selection, and indoor environmental quality.

Leak Detection and Repair (LDAR): Leak detection protocol, using either Photo-ionization detectors or infrared cameras promises to prevent volatile organic compound and hazardous air pollutant emissions from leaking equipment.

Lean Burn Engine: An engine that employs a fuel mixture with a higher air content than fuel as regulated by the AFRC with a normal exhaust oxygen concentration of 2% by volume, or greater.

Liquid Natural Gas (LNG): Natural gas that has been processed to remove either valuable components (e.g. helium) or those impurities that could cause difficulty downstream (e.g. water and heavy hydrocarbons) and then condensed into a liquid.

Lowest Achievable Emission Rate (LAER): Under the Clean Air Act, the rate of emissions that reflects (1) the most stringent emission limitation in the State Implementation Plan of any state for a given source unless the owner or operator demonstrates such limitations are not achievable; or (2) the most stringent emissions limitation achieved in practice, whichever is more stringent.

Low NOx Burners: One of several combustion technologies used to reduce emissions of nitrogen oxides.

Major Source: A stationary facility that emits a regulated pollutant in an amount exceeding the threshold level depending on the location of the facility and attainment with regard to air quality status. (See Source.)

Mass Spectrometry: Analytical technique used to measure the mass-to-charge ratio of ions.

Maximum Achievable Control Technology (MACT): Federal emissions limitations based on the best demonstrated control technology or practices in similar sources to be applied to major sources emitting one or more federal hazardous air pollutants.

Mean: Average.

Median: The middle value in a population distribution, above and below which lie an equal number of individual values; midpoint.

Megawatt (MW): One million watts of electricity (See Watt).

Melting Point: The temperature at which a solid becomes a liquid. At this temperature, the solid and the liquid have the same vapor pressure.

Mercury: A chemical element in the periodic table that has the symbol Hg. A heavy, silvery transition metal, mercury is one of five elements that are liquid at or near room temperature and pressure.

Mercury Deposition Network (MDN): The objective of the MDN is to develop a national database of weekly concentrations of total mercury in precipitation and the seasonal and annual flux of total mercury in wet deposition. The data will be used to develop information on spatial and seasonal trends in mercury deposited to surface waters, forested watersheds, and other sensitive receptors. See http://nadp.sws.uiuc.edu/mdn/

Mercury (Hg) Speciation: Mercury can assume many forms and, through interactions with the environment, can be transformed into a variety of structures. The most commonly known forms of mercury include: Elemental Mercury, divalent mercury (mercuric chloride) and methyl mercury.
The behavior of mercury in the atmosphere depends upon its form, or specie. Elemental mercury (Hgo) is typically not very reactive with global lifetime of a few months to a year and is thought to be transported significantly in the troposphere. Reactive gaseous mercury (RGM) species, are not well characterized chemically but are thought to be gaseous Hg(II)-bearing molecules such as HgCl2(g). RGM species are notable for being quickly deposited from the atmosphere to the surface and are thought to be readily available for conversion to methylmercury, a highly toxic form of mercury. Particulate mercury (Hg-P) is also quickly deposited and is often found in high concentrations near combustion sources. Although much lower in proportion than Hgo, the greater reactivity and deposition rates of RGM and Hg-P make them a larger environment concern. Chemical reactions that occur in the atmosphere can transform mercury between these various species.

Mesosphere: The layer of the Earth's atmosphere above the stratosphere and below the thermosphere. It is between 35 and 60 miles from the Earth.

Methane: A chemical compound with the molecular formula CH_4. It is the simplest alkane, and the principal component of natural gas. Burning one molecule of methane in the presence of oxygen releases one molecule of CO_2 (carbon dioxide) and two molecules of H_2O. It is also an important source of hydrogen in various industrial processes. Methane is a greenhouse gas.

Methyl Mercury: Mercury in the air eventually settles into water or onto land where it can be washed into water. Once deposited, certain microorganisms can change it into methylmercury, a highly toxic form that builds up in fish, shellfish and animals that eat fish. Fish and shellfish are the main sources of methylmercury exposure to humans. Methylmercury builds up more in some types of fish and shellfish than others. The levels of methylmercury in fish and shellfish depend on what they eat, how long they live and how high they are in the food chain. Mercury exposure at high levels can harm the brain, heart, kidneys, lungs, and immune system of people of all ages. Research shows that most people's fish consumption does not cause a health concern. However, it has been demonstrated that high levels of methylmercury in the bloodstream of unborn babies and young children may harm the developing nervous system, making the child less able to think and learn.

Minor Source: Any stationary source that does not qualify as a major source and directly emits, or has the potential to emit, less than one hundred tons per year or more of any air pollutant.

Mobile Sources: Sources of air pollution such as automobiles, motorcycles, trucks, off-road vehicles, boats, and airplanes. (See also stationary sources).

Monitoring: The periodic or continuous sampling and analysis of air pollutants in ambient air or from individual pollution sources.

National Ambient Air Quality Standards (NAAQS): Standards established by the United States EPA that apply for outdoor air throughout the country. There are two types of NAAQS. Primary standards set limits to protect public health and secondary standards set limits to protect public welfare.

National Emission Standards for Hazardous Air Pollutants (NESHAPS): Emissions standards set by the U.S. EPA for a hazardous air pollutant, such as benzene, which may cause an increase in deaths or in serious, irreversible, or incapacitating illness.

Natural Sources: Non-manmade emission sources, including biological and geological sources, wildfires, and windblown dust.

Net Metering: Arrangement that permits a facility (using a meter that reads inflows and outflows of electricity) to sell any excess power it generates over its load requirement back to the electrical grid to offset consumption.

Neurotoxin: A toxin that acts specifically on nerve cells.

New Mexico Public Regulation Commission: The New Mexico Public Regulation Commission (PRC) regulates the utilities, telecommunications, motor carriers and insurance industries to ensure fair and reasonable rates, and to assure reasonable and adequate services to the public as provided by law.

New Source Performance Standards (NSPS): Uniform national EPA air emission standards that limit the amount of pollution allowed from new sources or from modified existing sources.

New Source Review (NSR): A Clean Air Act requirement that State Implementation Plans must include a permit review, which applies to the construction and operation of new and modified stationary sources in nonattainment areas, to ensure attainment of national ambient air quality standards. The two major requirements of NSR are Best Available Control Technology and Emission Offsets.

Nitrate (NO_3): A salt of nitric acid with an ion composed of one nitrogen and three oxygen atoms.

Nitric Oxide (NO): Precursor of ozone, NO_2, and nitrate; nitric oxide is usually emitted from combustion processes. Nitric oxide is converted to nitrogen dioxide (NO_2) in the atmosphere, and then becomes involved in the photochemical processes and / or particulate formation. (See Nitrogen Oxides.)

Nitrogen: Chemical element, which has the symbol N, and atomic number 7. Elemental nitrogen is a colorless, odorless, tasteless and mostly inert diatomic gas at standard conditions, constituting 78.1% by volume of Earth's atmosphere.

Nitrogen Enrichment Mode: NOx decreases while particulate emissions increase.

Nitrogen Oxides (Oxides of Nitrogen, NOx): A general term pertaining to compounds of nitric oxide (NO), nitrogen dioxide (NO_2) and other oxides of nitrogen. Nitrogen oxides are typically created during combustion processes, and are major contributors to smog formation and acid deposition. NO_2 is a criteria air pollutant, and may result in numerous adverse health effects.

Nonattainment Area: A geographic area identified by the U.S. EPA as not meeting the NAAQS for a given pollutant.

Noncarcinogenic Effects: Non-cancer health effects which may include birth defects, organ damage, morbidity, and death.

Non-Industrial Source: Any of a large number of sources -- such as mobile, area-wide, indirect, and natural sources -- which emit substances into the atmosphere.

Non-Methane Hydrocarbon (NMHC): The sum of all hydrocarbon air pollutants except methane. NMHCs are significant precursors to ozone formation.

Non-Methane Organic Gas (NMOG): The sum of non-methane hydrocarbons and other organic gases such as aldehydes, ketones and ethers.

Non-Point Sources: Diffuse pollution sources that are not recognized to have a single point of origin.

Non-Road Emissions: Pollutants emitted by a variety of non-road sources such as farm and construction equipment, gasoline-powered lawn and garden equipment, and power boats and outboard motors.

NOx Traps: Operate in a two-step cyclic process. In the first stage the NOx trap adsorbs NOx while the engine operates in a lean-burn mode. In the second stage, the engine operates with excess fuel in the exhaust. The fuel decomposes on the catalyst and reduces the NOx to molecular nitrogen and water.

O_2 enrichment mode: Produces a dramatic reduction in particulate emissions at the expense of increased NOx emissions.

Opacity: The amount of light obscured by particle pollution in the atmosphere. Opacity is used as an indicator of changes in performance of particulate control systems.

Organic Compounds: A large group of chemical compounds containing mainly carbon, hydrogen, nitrogen, and oxygen. All living organisms are made up of organic compounds.

Oxidant: A substance that brings about oxidation in other substances. Oxidizing agents (oxidants) contain atoms that have suffered electron loss. In oxidizing other substances, these atoms gain electrons. Ozone, which is a primary component of smog, is an example of an oxidant.

Oxidation: The chemical reaction of a substance with oxygen or a reaction in which the atoms in an element lose electrons and its valence is correspondingly increased.

Oxidation catalysts: Element using a catalytic conversion for control of hydrocarbon and CO emissions.

Oxygenate: An organic molecule that contains oxygen. Oxygenates are typically ethers and alcohols.

Ozone (O_3): A strong smelling, pale blue, reactive toxic chemical gas consisting of three oxygen atoms. It is a product of the photochemical process involving the sun's energy and ozone precursors, such as hydrocarbons and oxides of nitrogen. Ozone exists in the upper atmosphere ozone layer (stratospheric ozone) as well as at the Earth's surface in the troposphere (ozone). Ozone in the troposphere causes numerous adverse health effects and is a criteria air pollutant. It is a major component of smog.

Ozone Depletion: The reduction in the stratospheric ozone layer. Stratospheric ozone shields the Earth from ultraviolet radiation. The breakdown of certain chlorine and / or bromine-containing compounds that catalytically destroy ozone molecules in the stratosphere can cause a reduction in the ozone layer.

Ozone-Forming Potential: (See Reactivity.)

Ozone Layer: A layer of ozone in the lower portion of the stratosphere -- 12 to 15 miles above the Earth's surface -- which helps to filter out harmful ultraviolet rays from the sun. It may be contrasted with the ozone component of photochemical smog near the Earth's surface which is harmful.

Ozone Precursors: Chemicals such as volatile organic compounds and oxides of nitrogen, occurring either naturally or as a result of human activities, which contribute to the formation of ozone, a major component of smog.

Particulate Matter (PM): Any material, except pure water, that exists in the solid or liquid state in the atmosphere. The size of particulate matter can vary from coarse, wind-blown dust particles to fine particle combustion products.

Passive Solar: A system in which solar energy alone is used for the transfer of thermal energy. Pumps, blowers, or other heat transfer devices that use energy other than solar are not used.

Permit: Written authorization from a government agency that allows for the construction and / or operation of an emissions generating facility or its equipment within certain specified limits.

Persistence: Refers to the length of time a compound stays in the atmosphere, once introduced. A compound may persist for less than a second or indefinitely.

Photovoltaic (PV) Module: An integrated assembly of interconnected photovoltaic cells designed to deliver a selected level of working voltage and current at its output terminals, packaged for protection against environment degradation, and suited for incorporation in photovoltaic power systems.

Pilot scale: Size of a system between the small laboratory scale (bench-scale) and full-size system.

Plant Pathology: The scientific study of plant diseases caused by pathogens (infectious diseases) and environmental conditons (physiological factors).

Plume: A visible or measurable discharge of a contaminant from a given point of origin that can be measured according to the Ringelmann scale. (See Ringelmann Chart.)

Plunger Lift System: Use gas pressure buildup in a well to lift a column of accumulated fluid out of the well. The plunger lift system helps to maintain gas production and may reduce the need for other remedial operations.

$PM_{2.5}$: Includes tiny particles with an aerodynamic diameter less than or equal to a nominal 2.5 microns. This fraction of particulate matter penetrates most deeply into the lungs.

PM_{10} (Particulate Matter): A criteria air pollutant consisting of small particles with an aerodynamic diameter less than or equal to a nominal 10 microns (about 1/7th the diameter of a single human hair). Their small size allows them to make their way to the air sacs deep within the lungs where they may be deposited and result in adverse health effects. PM_{10} also causes visibility reduction.

Pneumatic controls: Control systems using either compressed gas or air.

Point Sources: Specific points of origin where pollutants are emitted into the atmosphere such as factory smokestacks. (See also Area-Wide Sources and Fugitive Emissions.)

Polycyclic Aromatic Hydrocarbons (PAHs): Organic compounds which include only carbon and hydrogen with a fused ring structure containing at least two benzene (six-sided) rings. PAHs may also contain additional fused rings that are not six-sided. The combustion of organic substances is a common source of atmospheric PAHs.

Polymer: Natural or synthetic chemical compounds composed of up to millions of repeated linked units, each of a relatively light and simple molecule.

Pounds per million BTU (lb/mmBtu): A measure of the mass (of a pollutant) emitted for each million British thermal units (Btu) of energy fed to a combustion source. A BTU is defined as the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Precipitator: Pollution control device that collects particles from an air stream. (See Electrostatic Precipitator.)

Prescribed Burning: The planned application of fire to vegetation to achieve any specific objective on lands selected in advance of that application.

Prevention of Significant Deterioration (PSD): A permitting program for new and modified stationary sources of air pollution located in an area that attains or is unclassified for national ambient air quality standards (NAAQS). The PSD program is designed to ensure that air quality does not degrade beyond those air quality standards or beyond specified incremental amounts. The PSD permitting process requires new and modified facilities above a specified size threshold to be carefully reviewed prior to construction for air quality impacts. PSD also requires those facilities to apply BACT to minimize emissions of air pollutants. A public notification process is conducted prior to issuance of final PSD permits.

Primary Particles: Particles that are directly emitted from combustion and fugitive dust sources. (Compare with Secondary Particle.)

Produced water: Water extracted from the subsurface with oil and gas. It may include water from the reservoir, water that has been injected into the formation, and any chemicals added during the production/treatment process.

Production Tax Credit (PTC): an inflation - adjusted 1.5 cents per kilowatthour payment for electricity produced using qualifying renewable energy sources.

Programmic logic controller (PLC): Control software for engine mapping / reactant injection requirements used to control the SCR system.

Public Utility Regulatory Policies Act of 1978 (PURPA): One part of the National Energy Act, PURPA contains measures designed to encourage the conservation of energy, more efficient use of resources, and equitable rates. Principal among these were suggested retail rate reforms and new incentives for production of electricity by cogenerators and users of renewable resources.

Pulverized coal: is a coal that has been crushed to a fine dust in a grinding mill. It is blown into the combustion zone of a furnace and burns very rapidly.

Radionuclides: Atoms with an unstable nucleus, characterized by excess energy which is available to be imparted either to a newly-created radiation particle within the nucleus, or else to an atomic electron.

Reactive Organic Gas (ROG): A photochemically reactive chemical gas, composed of non-methane hydrocarbons, that may contribute to the formation of smog. Also sometimes referred to as Non-Methane Organic Gases (NMOGs). (See also Volatile Organic Compounds and Hydrocarbons.)

Reactivity (or Hydrocarbon Photochemical Reactivity): A term used in the context of air quality management to describe a hydrocarbon's ability to react (participate in photochemical reactions) to form ozone in the atmosphere. Different hydrocarbons react at different rates. The more reactive a hydrocarbon, the greater potential it has to form ozone.

Reasonably Available Control Measures (RACM): A broadly defined term referring to technologies and other measures that can be used to control pollution. They include Reasonably Available Control Technology and other measures. In the case of PM_{10}, RACM refers to approaches for controlling small or dispersed source categories such as road dust, woodstoves, and open burning.

Reasonably Available Control Technology (RACT): Control techniques defined in U.S. EPA guidelines for limiting emissions from existing sources in nonattainment areas. RACTs are adopted and implemented by states.

Reciprocating Internal Combustion Engine (RICE): An engine in which air and fuel are introduced into cylinders, compressed by pistons and ignited by a spark plug or by compression. Combustion in the cylinders pushes the pistons sequentially, transferring energy to the crankshaft, causing it to rotate.

Refraction: The change in direction of a light wave due to a change in its speed when it passes from one medium to another.

Regional Haze: The haze produced by a multitude of sources and activities which emit fine particles and their precursors across a broad geographic area. National regulations require states to develop plans to reduce the regional haze that impairs visibility in national parks and wilderness areas.

Regional Haze Rule: The Regional Haze Rule calls for state and federal agencies to work together to improve visibility in 156 national parks and wilderness areas such as the Grand Canyon, Yosemite, the Great Smokies and Shenandoah.
The rule requires the states, in coordination with the Environmental Protection Agency, the National Park Service, U.S. Fish and Wildlife Service, the U.S. Forest Service, and other interested parties, to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment. The first State plans for regional haze are due in the 2003-2008 timeframe. Five multi-state regional planning organizations are working together now to develop the technical basis for these plans.

Regulatory Impact Analysis (RIA): A tool used to assess the likely effects of a proposed new regulation or regulatory change.

Reid Vapor Pressure: Refers to the vapor pressure of the fuel expressed in the nearest hundredth of a pound per square inch (psi) with a higher number reflecting more gasoline evaporation.

Renewable Energy: Renewable Energy is energy derived from resources that are regenerative or, for all practical purposes, cannot be depleted.

Renewable Energy Resources: Energy resources that are naturally replenishing but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Renewable energy resources include: biomass, hydro, geothermal, solar, wind, ocean thermal, wave action, and tidal action.

Renewable Portfolio Standard (RPS): a mandate requiring that renewable energy provide a certain percentage of total energy generation or consumption.

Retrofit or retrofitting: The addition of new technology or features to older systems.

Rich Burn Engine: Any four-stroke spark ignited engine with a manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NOx (such as pre-combustion chambers) will be considered lean burn engines. Existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Ringelmann Chart: A series of charts, numbered 0 to 5, that simulate various smoke densities by presenting different percentages of black. A Ringelmann No. 1 is equivalent to 20 percent black; a Ringelmann No. 5 is 100 percent black. They are used for measuring the opacity or equivalent obscuration of smoke arising from stacks and other sources by matching the actual effluent with the various numbers, or densities, indicated by the charts.

Risk Assessment: An evaluation of risk which estimates the relationship between exposure to a harmful substance and the likelihood that harm will result from that exposure.

Risk Management: An evaluation of the need for and feasibility of reducing risk. It includes consideration of magnitude of risk, available control technologies, and economic feasibility.

Risk Management Plan (RMP): A document prepared by a project manager to foresee risks, estimate effectiveness, and to create response plans to mitigate them.

Sanctions: Actions taken against a state or local government by the federal government for failure to plan or to implement a State Implementation Plan (SIP). Examples include withholding of highway funds and a ban on construction of new sources of potential pollution.

Scrubber: An air pollution control device that uses a high energy liquid spray to remove aerosol and gaseous pollutants from an air stream. The gases are removed either by absorption or chemical reaction.

Secondary Particle: Particles that are formed in the atmosphere. Secondary particles are products of the chemical reactions between gases, such as nitrates, sulfur oxides, ammonia, and organic products.

Selective Catalytic Reduction (SCR) or selective non-catalytic reduction (SNCR): Selective catalytic reduction means a noncombustion control technology that destroys NOx by injecting a reducing agent (e.g., ammonia) into the flue gas that, in the presence of a catalyst (e.g., vanadium, titanium, or zeolite), converts NOx into molecular nitrogen and water.

Selexol: Selexol is the trade name for a physical solvent that is a mixture dimethyl ethers of polyethylene glycol. In the Selexol process, the solvent dissolves the CO_2 from the gas stream at a relatively high pressure, generally in the range of 300 – 1,000 psia. The resulting rich solvent can then either be let down in pressure and/or steam stripped to release and recover the CO_2.

Sensitive Groups: Identifiable subsets of the general population that are at greater risk than the general population to the toxic effects of a specific air pollutant (e.g., infants, asthmatics, elderly).

Sequestration: Capture and long term storage of carbon. See also Carbon Capture and Storage

Smog: A combination of smoke and other particulates, ozone, hydrocarbons, nitrogen oxides, and other chemically reactive compounds which, under certain conditions of weather and sunlight, may result in a murky brown haze that causes adverse health effects.

Smoke: A form of air pollution consisting primarily of particulate matter (i.e., particles released by combustion). Other components of smoke include gaseous air pollutants such as hydrocarbons, oxides of nitrogen, and carbon monoxide. Sources of smoke may include fossil fuel combustion, prescribed and agricultural burning, and other combustion processes.

Solar Energy: The radiant energy of the sun, which can be converted into other forms of energy, such as heat or electricity.

Solar Thermal Collector: A device designed to receive solar radiation and convert it into thermal energy. Normally, a solar thermal collector includes a frame, glazing, and an absorber, together with the appropriate insulation. The heat collected by the solar thermal collector may be used immediately or stored for later use. Solar Thermal Collector, Special: An evacuated tube collector or a concentrating (focusing) collector. Special collectors operate in the temperature (low concentration for pool heating) to several hundred degrees Fahrenheit (high concentration for air conditioning and specialized industrial processes).

Soot: Very fine carbon particles that have a black appearance when emitted into the air.

Source: Any place or object from which air pollutants are released. Sources that are fixed in space are stationary sources and sources that move are mobile sources.

Spark ignition (SI): Ignition of combustion within an engine using spark plugs with a high-intensity spark of timed duration to ignite a compressed fuel-air mixture within the cylinder. SI engines are available in sizes up to 5 MW. Natural gas is the preferred fuel in electric generation and CHP applications of SI.

Stack Gas Bypass: The practice of routing some portion of exhaust gas, often from a large boiler, around the pollution control equipment, and into the exhaust stack. This is usually done to introduce hot, unscrubbed, gas into the stack to mix with and raise the temperature of the cool, scrubbed gas above its acid dew point and/or to increase plume buoyancy and dispersion. If the gas cools to its acid dew point, acid mists and droplets may fall out near the stack, or corrode unprotected stack linings.

State Implementation Plan (SIP): The group of plans and regulations submitted by a state to the U.S. EPA for implementation of the federal Clean Air Act.

Stationary Sources: Non-mobile sources such as power plants, refineries, and manufacturing facilities which emit air pollutants. (See also mobile sources).

Still vent column: Emission point for regeneration of glycol streams, resulting in vapors of water, VOC and HAPs.

Stoichiometric engine: An engine with the chemically correct proportion of fuel to air in the combustion chamber during combustion.

Storage Tank: Any stationary container, reservoir, or tank, used for storage of liquids.

Stratosphere: The layer of the Earth's atmosphere above the troposphere and below the mesosphere. It extends between 10 and 30 miles above the Earth's surface and contains the ozone layer in its lower portion. The stratospheric layer mixes relatively slowly; pollutants that enter it may remain for long periods of time.

Subsidy: Financial assistance granted by the Government to firms and individuals.

Sulfur Dioxide (SO_2): A strong smelling, colorless gas that is formed by the combustion of fossil fuels. Power plants, which may use coal or oil high in sulfur content, can be major sources of SO_2. SO_2 and other sulfur oxides contribute to the problem of acid deposition. SO_2 is a criteria air pollutant.

Sulfur Oxides (SOx): Pungent, colorless gases (sulfates are solids) formed primarily by the combustion of sulfur-containing fossil fuels, especially coal and oil. Considered major air pollutants, sulfur oxides may impact human health and damage vegetation.

Syngas: Syngas is the gas product resulting from gasification processes and can be used as a fuel to drive power generation or a feedstock for chemical synthesis.

Tailpipe emissions: Products of burning fuel in the vehicle's engine emitted from the vehicle's exhaust system.

Thief hatch: Opening in the top of the stock tank that allows tank access to the interior of the tank for withdrawal or measurement of fluid.

Title V: A section of the 1990 amendments to the federal Clean Air Act that requires a federally enforceable operating permit for major sources of air pollution.

Topography: The configuration of a surface, especially the Earth's surface, including its relief and the position of its natural and man-made features.

Total dissolved solids (TDS): The combined content of all inorganic and organic substances contained in a liquid which are present in a molecular, ionized or micro-granular (colloidal sol) suspended form.

Total Suspended Particulate (TSP): Particles of solid or liquid matter -- such as soot, dust, aerosols, fumes, and mist -- up to approximately 30 microns in size.

Toxic Hot Spot: A location where emissions from specific sources may expose individuals and population groups to elevated risks of adverse health effects -- including but not limited to cancer -- and contribute to the cumulative health risks of emissions from other sources in the area.

Trading Credits: The basic concept of a cap and trade system is that the government turns a certain quantity of emissions into a marketable commodity, called a credit, which is then allowed to be bought and sold freely on the market. See http://www.epa.gov/airmarkets/trading/basics.html

Transmission System (Electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

Triethylene glycol (TEG) dehydrator: Any device in which a liquid glycol (including, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

Troposphere: The layer of the Earth's atmosphere nearest to the surface of the Earth. The troposphere extends outward about five miles at the poles and about 10 miles at the equator.

Turbine: A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction, or a mixture of the two.

Underground Storage Tank (UST): Refers to tanks used to store gasoline underground.

United States Environmental Protection Agency (U.S. EPA): The federal agency charged with setting policy and guidelines, and carrying out legal mandates for the protection of national interests in environmental resources.

Urea: An organic compound of carbon, nitrogen, oxygen and hydrogen, with the formula CON_2H_4 or (NH_2) CO_2 or CN_2H_4O. Used as a catalyst for SCR applications.

Vanadium: A chemical element in the periodic table that has the symbol V and atomic number 23. A rare, soft and ductile element, vanadium is found combined in certain minerals and is used mainly to produce certain alloys.

Vapor recovery unit (VRU): A system composed of a scrubber, a compressor and a switch. Its main purpose is to recover vapors formed inside completely sealed crude oil or condensate tanks.

Vehicle Miles Traveled (VMT): The miles traveled by motor vehicles over a specified length of time (e.g., daily, monthly or yearly) or over a specified road or transportation corridor.

Visibility: A measurement of the ability to see and identify objects at different distances. Visibility reduction from air pollution is often due to the presence of sulfur and nitrogen oxides, as well as particulate matter.

Visibility Reducing Particles (VRP): Any particles in the atmosphere that obstruct the range of visibility.

Volatile: Any substance that evaporates readily.

Volatile Organic Compounds (VOCs): Carbon-containing compounds that evaporate into the air (with a few exceptions). VOCs contribute to the formation of smog and / or may themselves be toxic. VOCs often have an odor, and some examples include gasoline, alcohol, and the solvents used in paints.

Watt (Electric): The electrical unit of power. The rate of energy transfer equivalent to 1 ampere of electric current flowing under a pressure of 1 volt at unity power factor.

Watthour (Wh): The electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Weight of Evidence: The extent to which the available information supports the hypothesis that a substance causes an effect in humans. For example, factors which determine the weight-of-evidence that a chemical poses a hazard to humans include the number of tissue sites affected by the agent; the number of animal species, strains, sexes, relationship, statistical significance in the occurrence of the adverse effect in treated subjects compared to untreated controls; and the timing of the occurrence of adverse effect.

Welfare-Based Standard (Secondary Standard): An air quality standard that prevents, reduces, or minimizes injury to agricultural crops and livestock, damage to and the deterioration of property, and hazards to air and ground transportation.

Wet Flue Gas Desulfurization (FGD): In wet scrubbers, the flue gas enters a large vessel (spray tower or absorber), where it is sprayed with water slurry (approximately ten percent lime or limestone). The calcium in the slurry reacts with the SO2 to form calcium sulfite or calcium sulfate. A portion of the slurry from the reaction tank is pumped into the thickener, where the solids settle before going to a filter for final dewatering to about 50 percent solids. The calcium sulfite waste product is usually mixed with fly ash (approximately 1:1) and fixative lime (approximately five percent) and disposed of in landfills. Alternatively, gypsum can be produced from FGD waste, which is a useful by-product.

Wind Energy: Energy present in wind motion that can be converted to mechanical energy for driving pumps, mills, and electric power generators. Wind pushes against sails, vanes, or blades radiating from a central rotating shaft.

Woodburning Pollution: Air pollution caused by woodburning stoves and fireplaces that emit particulate matter, carbon monoxide and odorous and toxic substances.

Zeolite: Minerals that have a micro-porous structure.

Zero Emissions Dehydrator: A Zero Emissions Dehydrator combines several technologies that lower emissions. These technologies eliminate emissions from glycol circulation pumps, gas strippers and the majority of the still column effluent. Rather than being released as vapor, the water and hydrocarbons are collected from the glycol still column, and the condensable and non-condensable components are separated from each other. The two primary condensable products are wastewater, which can be disposed of with treatment; and hydrocarbon condensate, which can be sold. The non-condensable products (methane and ethane) are used as fuel for the glycol reboiler instead of venting to the atmosphere.

Table of Mitigation Options Not Written with Rationale

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SECTION	MITIGATION OPTION TITLE	RATIONALE FOR NOT WRITING
Oil and Gas: Stationary RICE (Small and large engines)	Emission limit on existing engines (1g/hp hr and 2g/hp hr)	Will incorporate this into the NSPS mitigation option and note that it will apply to existing engines.
	Replacing ignition systems to decrease false starts	This option is generally covered in the Operation and Maintenance mitigation option
	Replace piston rod packing (pumps)	This will be added to the Operation and Maintenance mitigation option.
	Minimize (control?) engine blow downs	This is already a common industry practice and has been deleted as an option
	Utilize exhaust gas analyzers to adjust AFR	This was included in the Oxidation Catalysts and AFRC on Lean Burn Engines option.
	Smart AFRC (air-fuel-ratio-controller)	Included in the other AFRC options
	Replace gas engine starters with electric air compressors	Negligible emissions reductions for applying this option.
	Provide training for field personnel on engine maintenance with regard to AQ considerations	Incorporated into Option titled “Adherence to Manufacturers’ Operation and Maintenance Requirements”
Oil and Gas: Mobile and Non-Road		
Oil and Gas: Rig Engines	Analysis of all drill rigs – replace the dirtiest 20%	Will reference in Tier 2-4 Mitigation Option Development, but also move to overarching discussion to determine the priority on rig engine reductions
	Electric Powered Drill Rig	Not selected due to low feasibility around availability of electricity
Oil and Gas: Turbines		
Oil and Gas: Exploration & Production (Tanks)	Mufflers	Does not apply to Air Quality.
	Centralized Collection for Existing Sources	This option is not feasible for retrofit application in the San Juan Basin

SECTION	MITIGATION OPTION TITLE	RATIONALE FOR NOT WRITING
Oil and Gas: Exploration & Production (Dehydrators/Separators/ Heaters)	Centralized Dehydrators	Already or will be incorporated in other papers on centralization
	Optimization and automation	Incorporated into the Option under Stationary RICE subsection.
	Low/Ultra low NOx burners	Application not appropriate for the San Juan Basin, because most burners commonly used in the Four Corners Area smaller than the technology is capable of providing emission reduction.
	Install VRU	Principle of the option as applied is explained in the Option titled "Install VRU" under subsection for E&P Tanks.
	Centralized Dehydrators	Principle of the option is incorporated into the Option under Stationary RICE. Additionally, the San Juan Basin does not have a high need for wellhead dehydration.
Oil and Gas: E&P Pneumatics/ Controllers/ Fugitives	Directed inspection and maintenance program	Addressed by Option title "Specific Direction for How to Meet NSPS and MACT Standards: Directed Inspection and Maintenance" in Midstream section.
Oil and Gas: Midstream Operations	Install Flares	Never submitted.
Oil and Gas: Overarching Issues		
Power Plants: Future	Integrated Gasification Combined Cycle (IGCC) Political Aspects and Incentives	Combined with Integrated Gasification Combined Cycle (IGCC) Technical Aspects and listed as mitigation option "Integrated Gasification Combined Cycle (IGCC)"
Power Plants: Overarching	Four Corners Area Mercury Studies	Combined with Participate and Support Mercury Deposition Studies
Other Sources:	Apply Uniform Regulations Between Jurisdictions for Dust Control	Never submitted.
	Fugitive Dust Road Mitigation Plan	See option papers on oil & gas road dust mitigation.
	Include Multi-Modal Transportation Options in 2035 Transportation Plan	Scope of this option is very large. A proposal was submitted to DOE.
	Pursue Clean Cities Designation for Western Slope	This was not awarded by DOE. Not clear just who would house and how funding could be sustainable.
	Auto Licensing or Registration Additional Tax	Group determined this was unlikely to be economically feasible at this time.
	Oil and Gas Fleet Retrofit / Replacement	Numerous options were written as part of the oil & gas section dealing with vehicles.

SECTION	MITIGATION OPTION TITLE	RATIONALE FOR NOT WRITING
Other Sources:	Consider Ambient Air Quality Before Burning Prescribed Fire	Never submitted.
	Develop Controls on Agricultural Burning in Colorado	Never submitted.
Energy Efficiency, Renewable Energy, Conservation	Corporate Rebate/incentives for Energy Efficiency	Combined with Building Standards for Increased Commercial and Residential Energy Efficiency (EE)
	Pilot Neighborhood project to Change Behavior to Reduce Energy Use – Increase Efficiency	Combined with Audits of Low Income Areas to find Simple Solutions
	Solar/PV Applications	Never submitted.
	Optimization of Compression	Incorporated into the Option under Stationary RICE subsection titled "Optimization and automation and Centralized Collection for New Sources"
	Micro Turbines	Incorporated into Option titled "Cogeneration/Combined Heat and Power"
	Product Capture/Maximize Efficiency	Never submitted.
	Multi-Phase Pipeline	Never submitted.
	Comprehensive Impacts of efficiency	Never submitted.
	Efficiency/Conservation on individual level	Never submitted.
	Sustainable business practices	Never submitted.
	Zero Waste	Never submitted.

GENERAL: PUBLIC COMMENTS

General Public Comments

Comment
Air quality in the Four Corners Area has been studied and cussed and discussed for several decades while the pollution problems grow and grow. We sincerely hope that measurable benefits to our environment will be the product of this massive piece of work by the Four Corners Air Quality Task Force. Polluting industries and enforcement agencies cannot continue to "turn their backs" on what IS happening to the quality of our air. It is our right to breathe clean air. We all know that San Juan County has serious air quality issues. San Juan County is ranked in the top 10% of worst counties in the United States for toxic releases to the environment according to Scorecard, a pollution information web site. These toxic releases include volatile organic compound emissions from oil and gas facilities, and power plant emissions such as particulate matter (PM) and sulfur dioxide. Many other toxic emissions are listed. All of these pollutants are threats to human health, the land and water. Enough is Enough! Now is the time to take action to clean up our environment! Regulatory agencies need to begin much stronger enforcement of current regulations and work toward more stringent regulations. Further degradation of our environment is not acceptable. State cancer profiles show that this area has the highest rate of cancer in New Mexico. Respiratory disease is high in the Four Corners Area. A comprehensive health study for the entire Four Corners Area would most likely reveal even more alarming health problems among our population. Clean up of area coal fired power plants and mandatory emissions controls and clean up of oil and gas facilities are necessary for the health and well being of the people. Health is wealth.
I've not read all the details of the report but I think there seems to be something missing. I don't see any analysis of the future demand on this area in terms of energy. There is a fast growing school of thought that indicates coal can provide the energy bridge the United States needs to exit the Middle East. I think people need to understand that the coal resources here in the San Juan Basin could become a big part of a new energy strategy for transportation. Electric cars and electric high speed trains could be used to help replace the demand for middle east oil being used now for gasoline and jet fuel. If this happens and I think it is coming in the next 10 years, what will we see here? Is any planning being done for that? If you think there is a lot of CO_2 from 3 power plants, what if there were 20? This may seem like bad news but it's not if we have a plan. For less than the cost of the Iraq war, we could install the infrastructure to convert the coal here into H_2 and CO_2. The H_2 could be used in new power plants driving engines turning generators thereby reducing the requirement for steam from water and the CO_2 could be captured and piped to Bakersfield to be injected into the heavy oils there in enhance oil recovery. The power grid will would require significant upgrades to accommodate the additional load in addition to providing ways for wind and solar power to come on the system. Instead of planning for war, let's plan for peace. This is a big effort. We need a leader with some vision at the Federal level. Is there someone who could have understood the impact of the internet and pushed to develop that infrastructure? Internet super highway -> I say Energy Super Highway!

Comment
The Southern Ute Indian Tribe Growth Fund (SUGF) appreciates the opportunity provided to the public to allow for review and comment on the Draft Four Corners Air Quality Task Force Report (Version 7); furthermore SUGF, is appreciative of the tremendous undertaking of the various resources that have come together to develop a range of possible air quality mitigation options that may remedy air quality issues in the Four Corners area. SUGF understands that this document is non-conclusive, and does not convey consensus of the various participating bodies regarding the mentioned mitigation options. It is further understood that these developed options may be considered by the various regulatory bodies to be implemented into air quality management strategies. At that time, it is recommended that public participation similar to this effort be duplicated. As you may be aware, production of natural gas is critical to the Southern Ute Indian Tribe's (Tribe) economic base and growth. The SUGF, a private investment entity of the Tribe supports development of its natural resources, yet remains cognizant of its responsibility to protect the environment. This is exemplified through Tribal processes such as conditional approval(s) of future oil and gas development that will require significant mitigation measures involving installation of control technologies on compression units. Another significant development occurring is the continual development of the Tribe's Air Quality Program, through the establishment of the Southern Ute Indian Tribe/State of Colorado Environmental Commission.
BP believes that the establishment of the Four Corners Task Force is a very useful venue for stakeholders and regulators to discuss air quality issues with the ultimate goal of managing air quality in the region. Developing strategies to measurably improve air quality requires extensive technical, engineering and policy analyses. In addition, such analyses require time and should not be influenced by arbitrary schedules. BP believes that solutions to the issues should be crafted on the basis of air quality improvement and economic efficiency. Control requirements based on a "one size solution" may not result in measurable air quality improvements nor be the most economic solution for improving air quality. BP also believes that it is important for the Task Force to focus on understanding source receptor relations in the region through modeling and analysis of existing air quality data as well as emission data.
I could not find the Federal Register notification for this superficial 'public comment' period. This process is fatally flawed as proper 'government to government meetings' have not been held. The formal notification has not been provided to all American Indian Nations and official respective American Indian Nation Tribal Council has not been officially made known. How will such federal mandates affect the sovereignty of American Indian Nations? This appears to violate basic principles of American Indian Nation Treaties as it does the Law of Nations. It appears, these federal agencies are recruiting non-profits to further international agendas for their federal acquisitions while attempting to impose hidden taxation. These federal regulatory actions certainly appear to emphasize regulation without representation as it promotes no accountability while encouraging implementation of un-ratified international conventions such as Kyoto. I attended the first meeting held in Farmington New Mexico for the Four Corners area regarding Air Quality on November 4, 2005. I spoke with a federal officer in her official capacity who acknowledged this process was indeed implementing the Kyoto Treaty that is un-ratified by U.S. Congress. She also acknowledged that the way the federal agencies were working around this un-ratified treaty was by entering into Memorandums of Understanding (MOU) between the respective State governments. These MOU's are signed by State governors as is the case with New Mexico State Governor Bill Richardson. New Mexico Governor Richardson proposed adoption of a regional climate change scheme to California Governor Arnold Schwarzenegger as stated in Executive order June 9, 2005. New Mexico Governor Richardson displays a definite conflict of interest as he continues to enjoy the pleasure of the United Nations while acting as United Nations Ambassador and more of an International Citizen, during his term as New Mexico Governor. A man cannot serve two masters anymore than he can be a citizen of two countries.

Comment
I received an email from a member of Montezuma Vision Project May 2, 2007 who wrote in reference to membership; "Most of the people are progressives who are interested in promoting planning for good quality of life." The main intent behind those who claim to be Progressives is to reduce "right" to privilege and "liberty" to servitude. Progressives enjoy collectivism implemented upon the masses while they enjoy their appointed and self anointed aristocracy oligarchy. The first U.S. Progressive Party formed in 1912 and has found its niche in liberalism and the environmental movement. There are Progressives connected to Democratic Socialist parties. Progressives believe and implement the old Roman Prodigal estate schemes promoted by IUCN (International Union for Conservation of Nature) which in reality is promoting Sustainable Development as specified in Agenda 21- 1992 Rio Summit Declaration. The Kyoto Protocol was created by an Intergovernmental Panel on Climate Change established in 1988 jointly by World Meteorological Organization and the United Nations Environment Programme. The Convention (Kyoto Protocol To The United Nations Framework Convention On Climate Change) was adopted by the Conference of the Parties meaning Parties to the Convention, May 1992, while in New York. The Montreal Protocol on Substances that Deplete the Ozone Layer was adopted by the Conference of the Parties September 1987. The federal officer while I was at November 4, 2005 meeting, acknowledged this entire process was truly implemented the Untied Nations, World Bank, IMF, Federal Reserve, and agenda for Sustainable Development which is also known as Agenda 21. The federal officer told me that there is a system in place for schemes that allow for a 'pay to pollute' program. She provided the example of power plants on the East Coast that do not have state of the art environmental equipment and cannot be fitted or converted with such state of the art environmental equipment. Certificates from power plants in Western U.S. who are newer and have up dated equipment as well as cleaner coal, would sell certificates to the Eastern U.S power plants as a means of offsetting Eastern power plant pollution. In reality, this is a pay to pollute scheme that mirrors the new-politically correct scheme of paying to have a 'Carbon Imprint or Footprint'. Example: a representative from Nature Conservancy conducts a Carbon Imprint intake of your life. The calculations are conducted on life style such as how often a person drives a car, fly's an airplanes, rides a bicycle, uses a microwave oven and so forth. Once the representative determines the Carbon Imprint number, the person is expected to pay an outrageous sum of money (Federal Reserve Notes) to an environmental non profit of his or her choice to off set the Carbon Imprint. In reality, this is extortion at its best while providing a steady source of income to environmental non profits who may not otherwise obtain such vast forms of income. It certainly appears this entire scheme is just another form of taxation forced upon the public. While I was in attendance at November 4, 2005 meeting I listened to the key-note speaker talk of new EPA standards that must be implemented. In reality, he was telling the public this unfunded and unjustified federal mandate 'must' be complied to. Meanwhile, he mentioned the Four Corners area has dust & silt particles blown in from other larger cities as far away as Phoenix and Tucson Arizona and beyond. There were a lot of charts on the walls and the mercury issue in the Four Corners was displayed as being mainly caused from the power plants that exist in the area. First of all, there is a natural occurrence of mercury in the San Juan Mountains. Second, plants are known to absorb mercury from the ground. If the plants and trees absorb this mercury from the ground and a wildfire of significant proportions occurs what is going to happen? The mercury will be released by residual ash and debris back into the ground and even into the water supply. This cycle was not demonstrated at this meeting nor is it ever discussed. This monitoring process and so called evidence collecting done in this entire process is fatally flawed while it certainly indicates fatal deficiencies in the precision in monitoring as it suggests other uncertainties.

Comment
The picture displayed upon the website depicting this proposed Four Corners Air Quality catastrophe is fatally flawed. Photographs can be easily manipulated to reflect whatever the crisis especially with today's technology. The pictures did not show what type of a day it was such as was it a cold day or a hot day? Sometimes in this area of the Four Corners depending upon what time of the morning and what moisture is in the air, visibility can be poor from the natural moisture in the air as well as wind passing through can cause dust from the ground to be in the air. The EPA expecting to regulate such natural processes in nature is absurd. The natural occurrences were not discussed at this meeting anymore than it was reflected in any of the charts or photographs. I see this entire process as in terminal as it is fatally in error. Most of all, I see federal agencies and cohorts attempting to play God while trying to control nature. This is preposterous to claim the environment that includes animals, plants and all of nature is above humans. This is perversions of natural law at its best especially when EPA claims it can control wind, dust and weather while expecting an area such as the Four Corners to keep that dust from blowing in from other areas. It is just as absurd to create this hyped up crisis just to sell certificates to pollute and extort money from the public. Cease and desist all these actions of implementing un-ratified illegal international treaties through abusing MOU's and other such agreements. Stop trying to play God while creating a crisis just to extort money from the public and expand progressivism.