Four Corners Air Quality Task Force

Draft Report of Mitigation Options

Version 5
January 10, 2007
Four Corners Air Quality Task Force

The draft report is a compilation of mitigation options drafted by members of the Four Corners Air Quality Task Force. The agencies involved have not reviewed or adopted these options at this time. These options will be considered following the completion of the Task Force in December 2007.

Members List [To be added]

Interested Parties List [To be added]

Executive Summary

[To be written]

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Oil and Gas

ENGINES: STATIONARY RICE

Mitigation Option: Industry Collaboration

I. Description of the mitigation option

Overview

- This option explores the possibility of industry collaboration toward affecting mandating emission control technologies [8/4/06] Expansion: *(e.g., three-way catalytic converters with air-to-fuel-ratio controllers)* that would be implemented by engine manufacturer's for building future engines, especially those used in association with natural gas fired compressor engines and are smaller horsepower of generally less than 200 hp [8/4/06] Clarification: *site-rated*.

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.

Economic

- This would require a large capital investment from both companies and engine manufacturer's to achieve this result. This would result in replacement of older compressor engines, particularly those less than 200 hp, with new ones at 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. [8/4/06] Expansion: *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.

B. Indicate the most appropriate agency(ies) to implement: State Environmental Agencies

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.
[8/4/06] Expansion: *EPA has established 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.

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

IV. Background data and assumptions used
Emission inventories compiled for the Farmington, NM BLM Resource Management Plan (2003); 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 feasibility. Medium 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.

Mitigation Option: Install Electric Compression

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

<u>Overview</u>

- 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.

<u>Air Quality/Environmental</u>

- Elimination of criteria pollutants that occur with the combustion of hydrocarbon fuels (natural gas, diesel, gasoline). Displacement of emissions to power generating sources (utilities).

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<u>Economics</u>

- 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.

<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.
- 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.

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

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.

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

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 (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 which groups:
Possibly the Cumulative Effects Group due to indirect emission increases from coal-fired plants.

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, thus 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.
- [8/4/06] Clarification: *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.*

Air Quality and Environmental Benefits

- The benefits would 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.

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.

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 a 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.
- [8/4/06] Expansion: *There is potential for increased noise for those living close to these centralized facilities.*

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.

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. [8/4/06] Clarification: *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.

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

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

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: 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.

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.

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

<u>A. Mandatory:</u> Compliance with the EPA NSPS will be mandatory. [8/4/06] Clarification: *This would apply to all newly manufactured, modified and reconstructed engines after the NSPS effective dates.* [11/1/06] Clarification: *'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.*

[11/1/06] 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. [11/1/06] Expansion: *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.

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. [11/1/06] Clarification: *(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. [11/1/06] Clarification: *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. [8/4/06] Expansion: *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 Low [11/1/06] Differing Opinion: *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 a SCR (selective catalytic reduction) system. 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 requirements of 40F.

SCR systems [8/4/06] Clarification: *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. [8/4/06] Ed: *See the mitigation option on the use of oxidation catalysts for reduction levels achieved for the pollutants.*

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.

B. Environmental: Post catalyst NOx levels of <0.15g/bhp-hr.

C. Economic: Cost of SCR system and maintenance are an increased cost to the packager and end user.

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.

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 None.

Mitigation Option: Use of NSCR / 3-Way Catalysts and Air/Fuel Ratio Controllers on 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. 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) an 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 are utilized on stoiciometric 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.

[8/4/06] Clarification: *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.*

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.

[8/4/06] Differing Opinion: *This option should be mandatory, implemented and enforced by the states.*

B. Indicate the most appropriate agency(ies) to implement: [8/4/06] Ed: *States,* Tribes and/or BLM, due to the fact that they are already involved in air quality regulations.

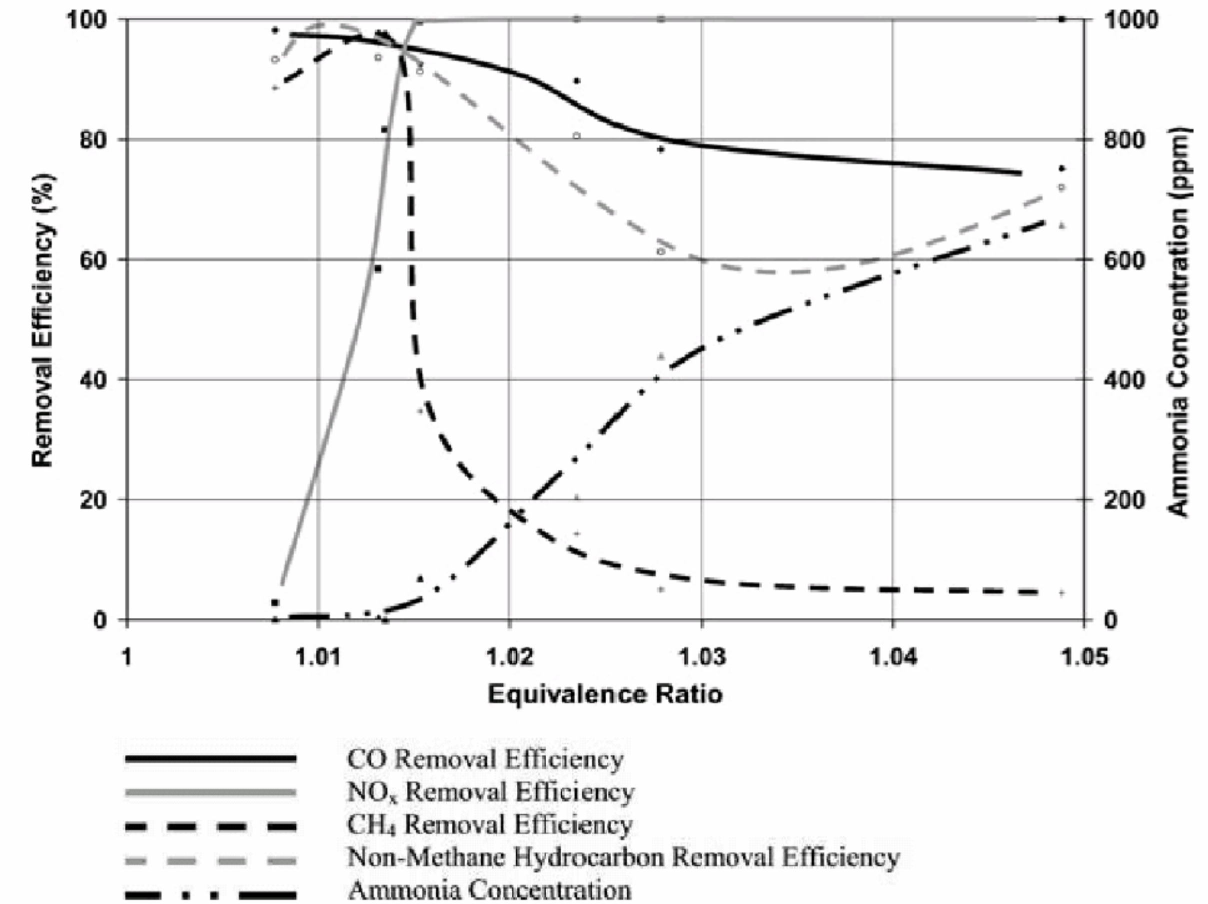
III. Feasibility of the option
A. Technical: Engines can be retrofitted in the field ½ a day or less. Catalysts do have a life span and will lose their efficiencies. However, under ideal operating parameters and with consistent engine maintenance, the life span of a catalyst can easily be up to 5 years. 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.
B. Environmental: Minimum of 90% NO_X, CO, HC, and Formaldehyde emission reduction. [8/4/06] Expansion: *Some increase in ammonia emissions would result, however, it is not known if this increase would be significant.*
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 man power, 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"

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:

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:



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.

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. Lean Burn Engines already have low uncontrolled NO_X emission values. 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 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.

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

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.

[8/4/06] Differing Opinion: *This option should be mandatory, implemented and enforced by the states.*

B. Indicate the most appropriate agency(ies) to implement: [8/4/06] Ed: *States,* Tribes and/or BLM, due to the fact that they are already involved in air quality regulations.

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.

B. Environmental: Minimum of 90% CO, HC, and Formaldehyde emission reduction.

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 man power, 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"

V. Any uncertainty associated with the option (Low, Medium, High)
LOW, this is a proven technology with years of results.

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: 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.

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.

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

III. Feasibility of the option

A. Technical: Some [8/4/06] Ed: *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.

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.

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)

[8/4/06] Expansion: *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
- Several manufacturers offer engines that meet this specification
- NSCR catalytic reduction can be added at reasonable cost [1/10/07]Expansion*: 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

II. Description of how to implement

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. 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 BLM and the New Mexico and Colorado environment departments.

III. Feasibility of the Option

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. [1/10/07] Clarification: *Economic feasibility is acceptable for many new engines since the equipment is somewhat more expensive*. [1/10/07]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.* 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.

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.

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.
[1/10/07] Differing Opinion: *EPA has proposed a 1.0 g/bhp-hr NOx limit for new SI engines, ≥ 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: Provide Training For Field Personnel on Engine Maintenance With Regard to AQ Considerations (forthcoming)

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

This options paper investigates the status of four new and/or evolving emissions-control technologies. They are: laser ignition, air-separation membranes, rich-burn engine with three-way catalyst, and lean-burn NOx catalyst.

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.

A. Laser Ignition

I. <u>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 are 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

To be determined.

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

To be determined.

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

To be determined.

B. 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 partuculate 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. <u>Description of how to implement</u>

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

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. [***insert specific references here***]

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

To be determined.

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

To be determined.

C. 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

www.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

To be determined.

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

To be determined.

D. 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 (N_2O) 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 (N_2O). 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

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

To be determined.

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

To be determined. The issue of incomplete NOx reduction that leaves some nitrous oxide (N_2O) may be moot if active lean-burn NOx catalysts cannot meet future emissions regulations.

Summary

Four technologies are reported: laser ignition, air-separation membranes, rich-burn engine with three-way catalyst, 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 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 which 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. [8/4/06] Clarification: *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 [8/4/06] Clarification: *of water and associated pollutants* off the roadway, (3) impacts to vegetations, (4.) salt loading to river systems.

[8/4/06] Differing Opinion: *Produced water in the Four Corners region contains toxins and therefore should not be used for dust mitigation.*

[8/4/06] Expansion: *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*

[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).*

Selenium	*0.080*	*ND*	*0.0171*	*ND*
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.*

[8/4/06] Expansion: ***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 [8/4/06] Ed: *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

[8/4/06] Expansion: *It may also be necessary to include the states in the implementation of any permitting process related to roadspreading 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 roadspreading 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.

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[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.*
[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. . ."*

[8/4/06] Expansion: *"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 own guidelines or policies to ensure that roadspreading practices are carried out in an environmentally sound manner.*

<u>B. Environmental:</u> 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.

[8/4/06] Expansion: *Most jurisdictions that allow roadspreading 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 roadspreading 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 roadspreading 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 <u>and</u> <u>BTEX</u> 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 roadspreading purposes.

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

<u>IV. Background data and assumptions used</u>

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 road work already completed.

<u>V. Any uncertainty associated with the option (Low, Medium, High)</u>

Medium uncertainty to environment (water quality and vegetation).

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[8] *http://www.dep.state.pa.us/dep/deputate/minres/oilgas/fs1801.htm*

[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*

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.

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 work load 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.

[8/4/06] Expansion: *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, 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.

[8/4/06] Expansion: *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. (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 truck loads 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 [8/4/06] Ed: *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. (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.

[8/4/06] Expansion: *Low sulfur diesel can continue to 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**:** [8/4/06] Ed: *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.

[8/4/06] Expansion: *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, 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.

[8/4/06] Expansion: *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 $PM_{2.5}$ 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 [8/4/06] Clarification: *(including produced water tanks, condensate tanks and/or crude oil tanks)* in socio-economically disadvantaged communities.

[8/4/06] 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. [8/4/06] Expansion: *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. [1/10/07] Clarification: *The EPA study only looked at the "summer" blend of diesel emulsion. There is no data available to evaluate 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. [1/10/07] 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. [1/10/07] Expansion: *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. [1/10/07]Clarification: *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. [1/10/07] 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. [1/10/07] Differing opinion: *The power penalties, incremental mixing and storage equipment, and increased technical knowledge necessary make this option do-able, but not necessarily simple.* 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.

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. [1/10/07] 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. [1/10/07] 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. [1/10/07] 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 [8/4/06] Ed: *Four Corners region*.

Benefits

- Air Quality - Natural gas engines emit less and NOx,
  - ~ 85% reduction of NOx vs. Tier I engines [1/10/07] Expansion: *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 [1/10/07] Expansion: *see above.*
- [8/4/06] Expansion: *Air Quality – 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. [1/10/07] Differing opinion: *On a purely fuel basis this may be true without considering the retrofit costs.*
  - Savings in fuel cost is [8/4/06] Ed: *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. [1/10/07] Expansion: *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.*
  - [1/10/07] Expansion: *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 [1/10/07] Expansion: *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. [1/10/07] 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
[1/10/07] Differing opinion: *See LNG comments above*.
[1/10/07] Expansion: *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.*

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)

<u>I. Description of the mitigation option</u>
Selective Catalytic Reduction (SCR)
<u>Description</u>
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. [1/10/07] Expansion: *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.
- [8/4/06] Expansion: *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 which 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. [1/10/07] 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. [1/10/07] Expansion: *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. [1/10/07] 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:

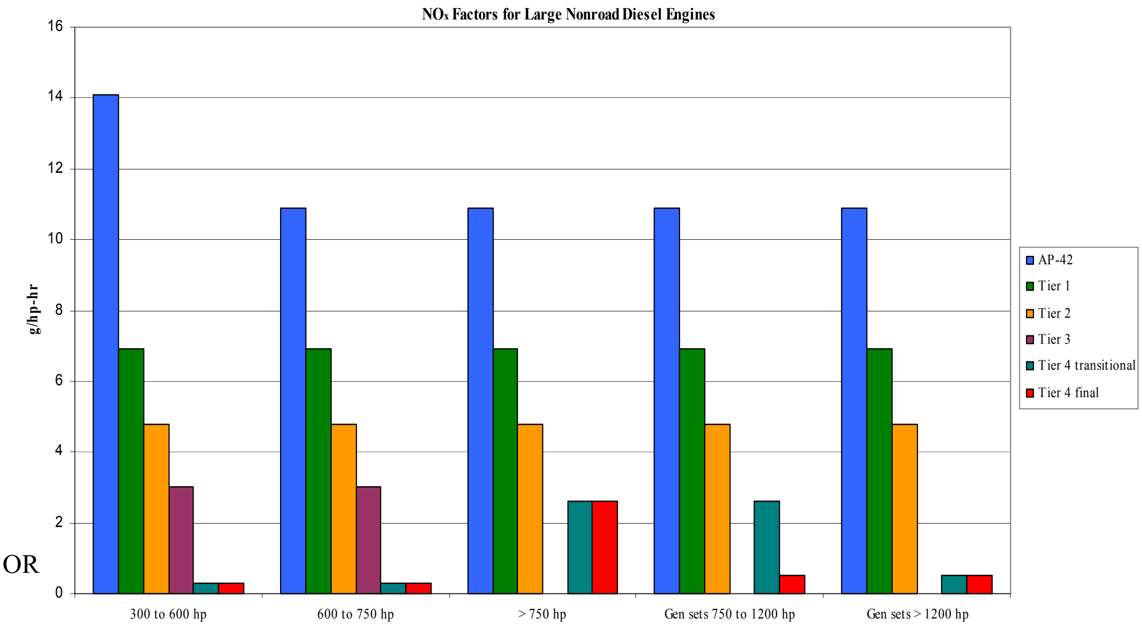
Clean Air Nonroad Diesel - Tier 4 Final Rule: Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel, 69 FR 38957, June 29, 2004

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

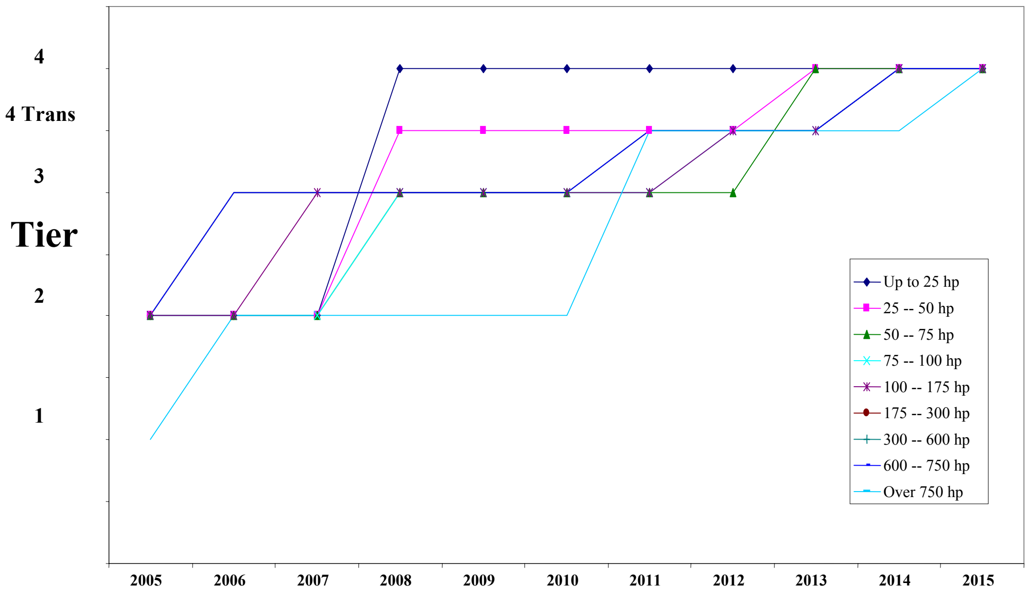


Table 1. Nonroad CI Engine Emission Standards[a]

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

4

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 (<u>indicate if assistance is needed from Cumulative Effects and/or Monitoring work groups)</u>

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, 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 Closed or Open Crankcase Ventilations (CCV / OCV)

[Unknown what this is referring to, same as EGR? Retrofit closed or open crankcase ventilations (CCV / OCV)?]

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.

[8/4/06] 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 [1/10/07] Ed.: *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.

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. There are currently no mechanisms or rules to require BMPs as 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 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.
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)

I. Description of the mitigation option

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.

II. Description of how to implement

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

III. Feasibility of the option

A. Technical: The use of VRUs for operating tank batteries is technically feasible.
B. Environmental: The environmental benefits of reduced VOC pollution are well documented.
C. Economic: 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.

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.

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

<u>I. Description of the mitigation option</u>
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. [1/10/07] Clarification*: 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 is 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.

<u>II. Description of how to implement</u>
<u>A. Mandatory or voluntary:</u> 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.
<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 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. Using gas blanket technology requires such tanks to withstand about 100 [1/10/07] Ed.: *psig, which* increases the costs for tanks substantially.
<u>B. Environmental:</u> The environmental benefits of reduced VOC pollution are well documented.
<u>C. Economic:</u> 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.

<u>IV. Background data and assumptions used</u>
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).

<u>V. Any uncertainty associated with the option</u> Low.

<u>VI. Level of agreement within the work group for this mitigation option</u>
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.

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.

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 (indicate if assistance is needed from Cumulative Effects and/or Monitoring work groups)

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]
B. Environmental
Under some environmental conditions (e.g., high temperatures) this option becomes less feasible.
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]

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

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 Task Force work groups (please describe the issue and which 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/OCEA, 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

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

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.

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

<u>A. Mandatory or voluntary:</u> 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.
<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 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.
<u>B. Environmental:</u> The environmental benefits of reduced NOx, CO, and NMHC pollution are well documented.
<u>C. Economic:</u> 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.

<u>IV. Background data and assumptions used</u>
Most fired units in the Four Corners area are utilized during the time period from November through March to achieve their objective.

<u>V. Any uncertainty associated with the option (Low, Medium, High)</u> Low.

<u>VI. Level of agreement within the work group for this mitigation option</u> TBD.

Mitigation Option: Portable Desiccant Dehydrators

I. Description of the mitigation option, including benefits (air quality, environmental, economic, other), tradeoffs (one pollutant for another, etc.) and burdens (on whom, what).

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.

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 (indicate if assistance is needed from Cumulative Effects and/or Monitoring work groups)

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.

B. Environmental

Desiccant dehydration systems work best under certain gas temperature and pressure conditions.

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.

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 (indicate if assistance is needed from Cumulative Effects and/or Monitoring work groups)

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.

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]

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.

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 (indicate if assistance is needed from Cumulative Effects and/or Monitoring work groups)

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]

B. Environmental

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.

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

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] 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 assumption is that combustion processes associated with flares efficiently convert 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.

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.

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]

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

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
- 29 tons VOCs, and 1 ton HAPs (assumption: half of the gas is flared per completion, and the flare operates at 50% efficiency).[14]

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. <u>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.</u>

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
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 (indicate if assistance is needed from Cumulative Effects and/or Monitoring work groups)
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/m^3)	Product	Volume (mg/m^3)
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	SO_2	NO_x	CO	PAHs	H_2S	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
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								
			FLA RING					
Affects cardiovascular system and can cause problems within the central nervous system						**VEN TING**		
Causes haze that can migrate to sensitive areas such as National Parks	**VEN TING**							
	FLA RING	**FLA RING**	**FLA RING**	**FLA RING**				**FLAR ING**
Contributes to global warming	**VEN TING**							

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.

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 recovers 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.

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. The green completion process has been reviewed by EPA and is listed under "Recommended Technologies and Practices" on EPA's Gas Star web site: http://www.epa.gov/gasstar/techprac.htm

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.

IV. Background data and assumptions used
Information on Green Completions comes from EPA's Gas Star 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.

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 [1/10/07] Ed.: *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.

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.

EXPLORATION & PRODUCTION: PNEUMATICS / CONTROLLERS / FUGITIVES

Mitigation Option: Optical Imaging to Detect Gas Leaks

I. <u>Description of the mitigation option:</u>
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. <u>Description of how to implement</u>
A. <u>Mandatory or voluntary:</u> 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 web site referenced below.
C. Economic: EPA reports that optical leak detection surveys pay for themselves in less than a year.

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 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

I. Description of the mitigation option

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 normal 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.

II. Description of how to implement

A. Mandatory or voluntary: 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. 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 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.

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.

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.

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.

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.

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.

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.

[8/4/06] 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.*

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.

> [8/4/06] 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

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. <u>Level of agreement within the work group for this mitigation option</u> TBD.

VII. <u>Cross-over issues to the other source groups</u> Impacts from trucks and roads may overlap with Other Sources WG.

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.

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 by the 4CAQTF. 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).

Benefits: 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[10] 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: [8/4/06] Ed: *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.

   [8/4/06] Expansion: *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).

IV. Background data and assumption used

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[10] 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.

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[11] 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 pay-back 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.

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

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[11] BP, Burlington Resources, ConocoPhillips, Devon Energy, Williams Production, Energen Resources, and XTO Energy

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 GasSTAR 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 GasSTAR 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 GasSTAR 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.

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.

Power Plants

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 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 Distributed Control System (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").
[11/1/06] Clarification: *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%. [11/1/06] Expansion: *Earn NOx Trading Credits as future regulations may require*. [11/1/06] Expansion: *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.
[11/1/06] Expansion: *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.

In many instances, the neural net can actually increase CO emissions. This is because you actually can run right up to your CO limit most of the time - while without the neural net you generally try to provide yourself with a cushion because by the time you realize you are approaching your limit it takes a fair amount of time to manually adjust the combustion. Also, generally, lower NO_x emissions mean higher CO emissions (at least with combustion controls).

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 4CPP. There may be some grants available to help fund such upgrades to existing power plants in Four Corners area.

[11/1/06] Expansion: *4CPP 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.

[1/10/07] 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.

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 4CPP 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:

1. Unit #1 is 190 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
2. Unit #2 is 190 gross MW dry bottom wall -fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
3. Unit #3 is 253 gross MW dry bottom wall -fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
4. Unit #4 is 818 gross MW cell-burner: 0.15 lb SO_2/mmBtu and 0.45 lb NO_x/mmBtu
5. 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.

[1/10/07] Expansion: *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.*

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.

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 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

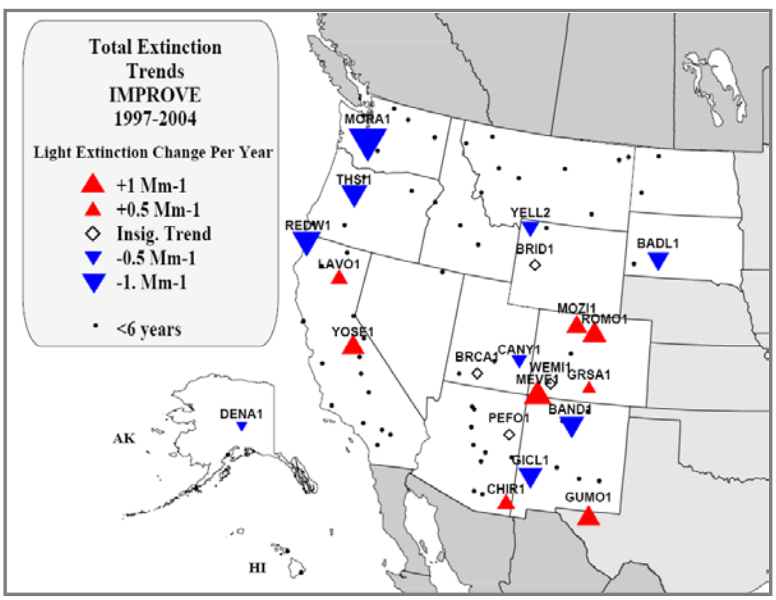


Figure 1.b. WRAP Sulfate Extinction Trends

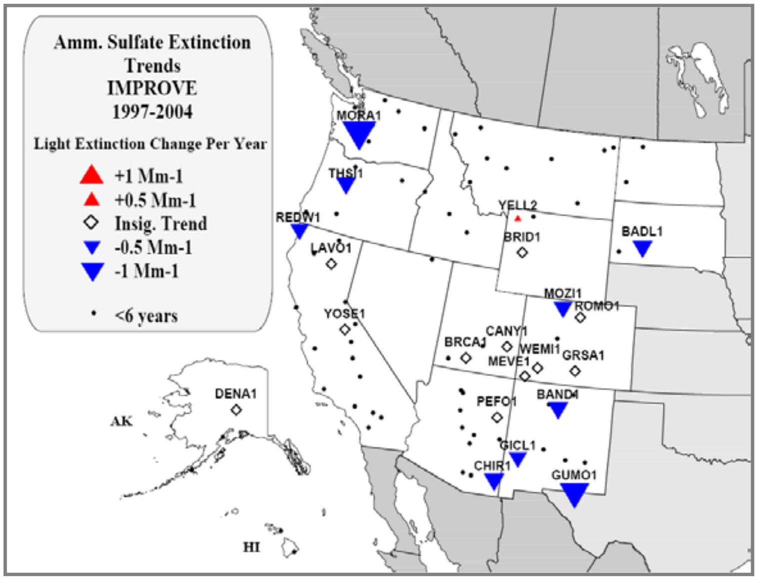


Figure 1.c. WRAP Nitrate Extinction Trends

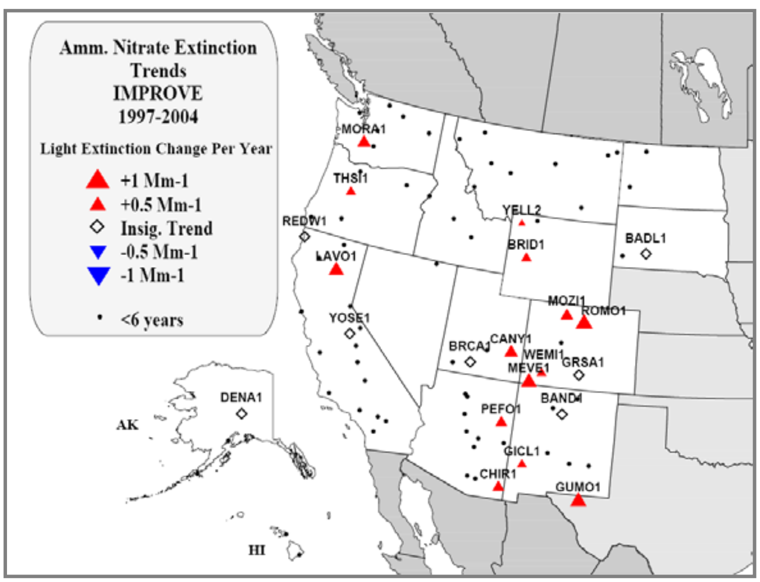


Figure 2. FCPP Emission Trends

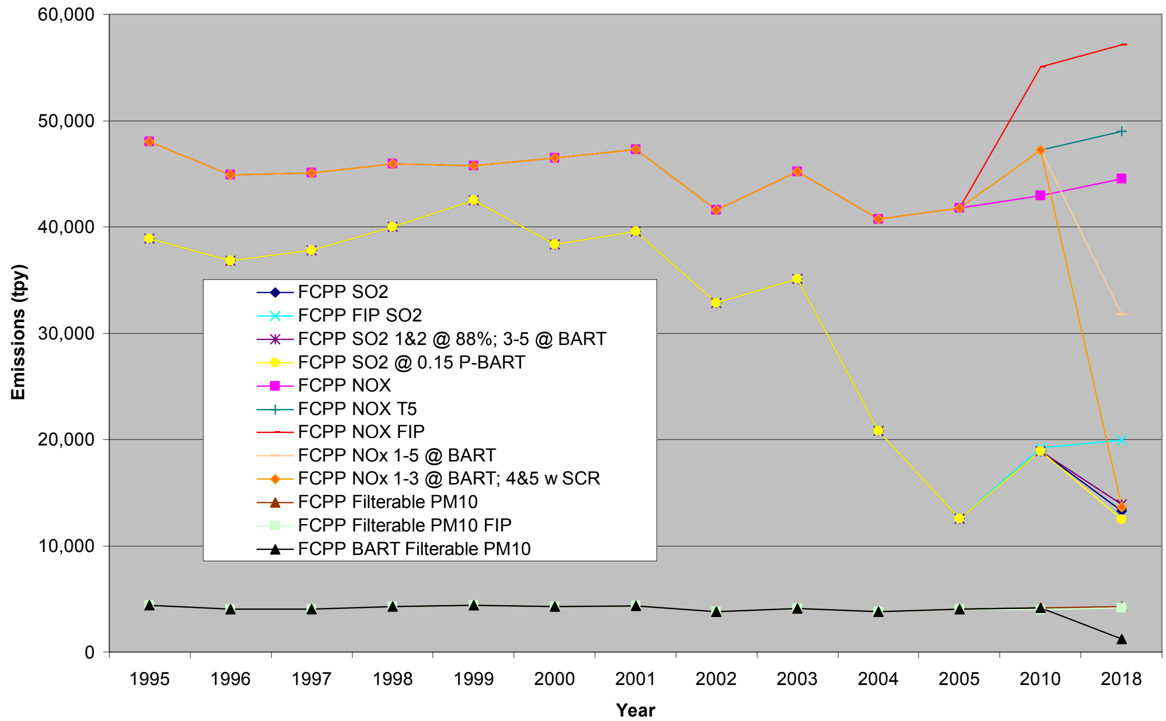


Figure 3. FCPP 2018 SO2 vs. Control Strategy

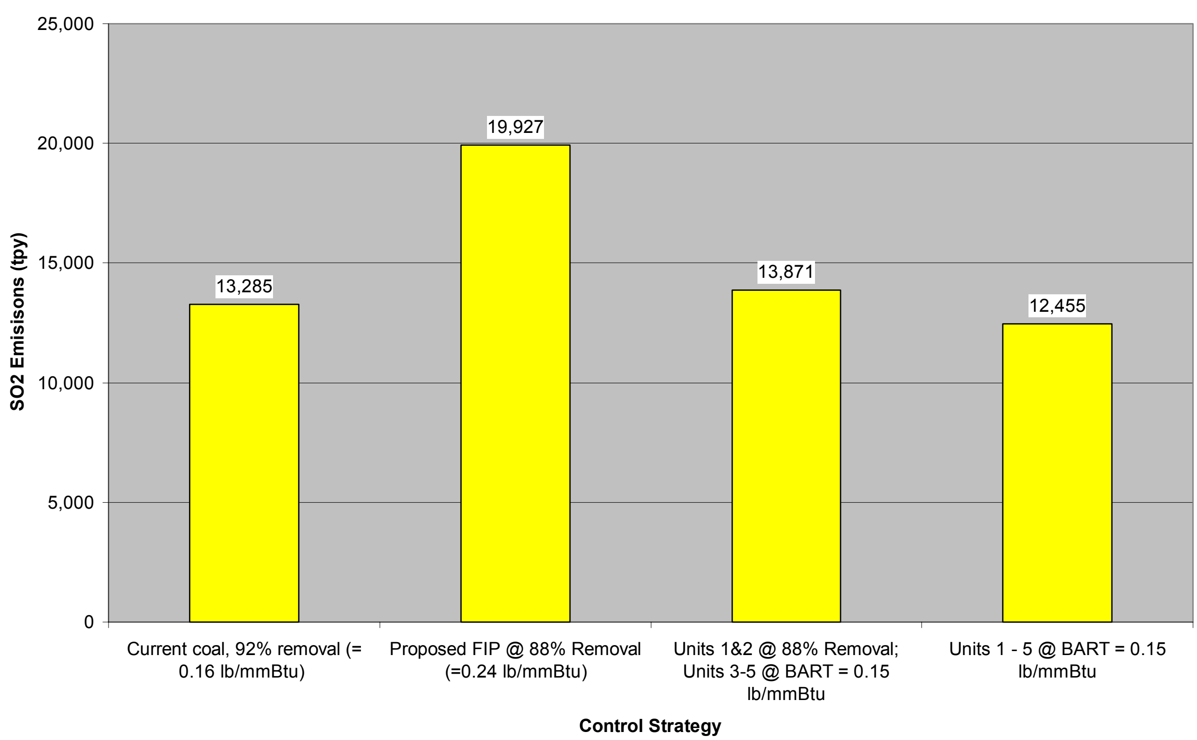
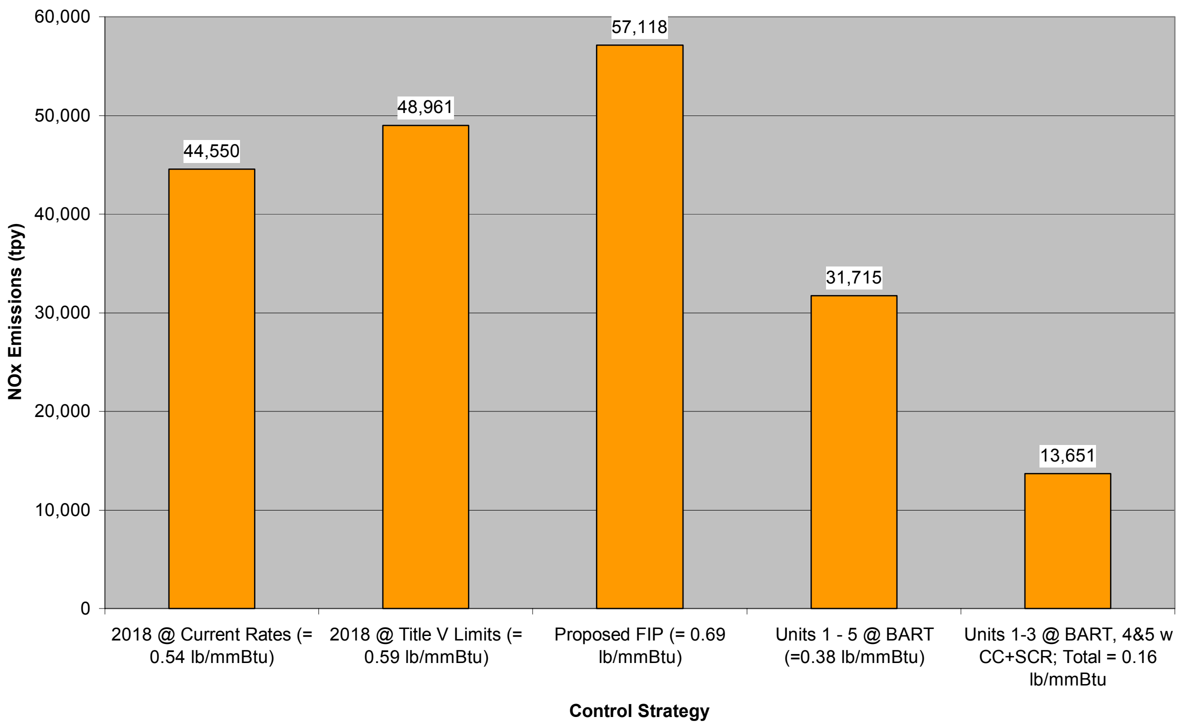


Figure 4. FCPP 2018 NOx Emissions vs Control Strategy



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 powerplants 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:

6. Unit #1 is 359 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
7. Unit #2 is 359 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
8. Unit #3 is 555 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
9. 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) [1/10/07] Clarification: *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)

In order to meet the PM_{10} limit, PSNM will replace all four existing Electrostatic Precipitators with Fabric Filters. [1/10/07] Clarification: *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.

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.

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

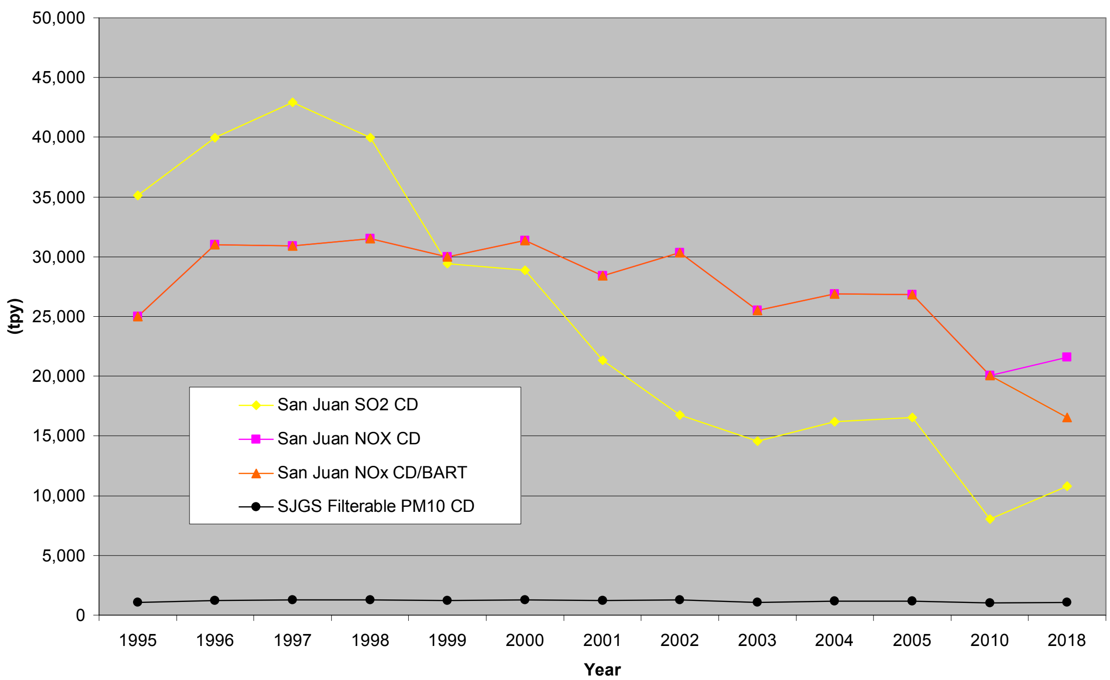
V. Any uncertainty associated with the option (Low, Medium, High)
Uncertainties in SJGS's ability to meet the BART presumptive limit for SO2 include future coal quality. Future emissions of SO_2, NO_x and PM10 will depend on future utilization, which at this point has been predicted.

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 [11/1/06] Ed: *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 an 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 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%.

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%. [11/1/06] Expansion: *In fact, data indicates that a 92% removal, or 0.16 lbs/MMbtu SO2 limit was achieved.* The parties involved in the test program have agreed that a new rule should propose to require 88% efficiency for the Four Corners Power Plant (6). [11/1/06] Expansion: *Parties are interested, however, in a mass emissions limit as opposed to removal rate to protect against air quality degradation from higher sulfur coal.*

72% SO_2 removal resulted in approximately 22,450 Tons/yr SO_2 emissions. The new emissions control 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

Benefits: SO_2 removal increase. Possible co-benefits 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

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 reduction 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. Proposed 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 removal 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,
[11/1/06] Ed: *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).

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).

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%.

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%. 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 increase loading to the particulate collection stage as PM10 (and PM2.5) (2).
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.

[11/1/06] Expansion: *Any analysis should compare the cost of SCR to the costs of combustion controls.*

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
[11/1/06] Expansion: *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 SCR process is subject to catalyst deactivation over time (2).

C. Economic – Retrofit costs. Additional maintenance costs

*Cumulative Effects Work Group – How would 50% 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"

<u>V. Any uncertainty associated with the option</u> High.

<u>VI. Level of agreement within the work group for this mitigation option</u> To Be Determined.

<u>VII. Cross-over issues to the other Task Force work groups</u>
Oil & Gas industry may also look at SCR as a method to reduce natural gas compressor NO_x emissions

Mitigation Option: BOC LoTOx^{TM} 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^{TM} 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^{TM} 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^{TM} 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^{TM} 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^{TM} 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^{TM} 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.

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. [1/10/07] Expansion: *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 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 emission. However, our permit requirement will be reduced from 0.05 lbs/mmbtu to 0.015 lbs/mmbtu.)*

[1/10/07] Clarification: *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. [1/10/07] Clarification: *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.

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.

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.
[11/1/06] Expansion: *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.*

[1/10/07] Expansion: *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.

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 limit for NOx at Four Corners Power Plant is 0.7 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 [11/1/06] Ed: *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.
[1/10/07] Expansion: *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
[11/1/06] Clarification: *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)). [11/1/06] Expansion: *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).

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.

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
[1/10/07] 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

[1/10/07] Expansion: *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
SO2	3,315	3.61	0.068	0.012	n/a	3,319
PM[2]	553	1.02	0.083	0.015	16.1	570
PM10[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

H2SO4	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: 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.

[1/10/07] Expansion: *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: 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.

b. Speciated 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 personal 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

[1/10/07] Expansion: *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)

I. Description of the mitigation option
[11/1/06] Clarification: *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)). [11/1/06] Expansion: *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).

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 (2).

Benefits: 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 CO_2 emissions from IGCC plants would be cheaper and less energy intensive than in conventional coal plants (3, 6)

Tradeoffs:
Burdens: IGCC has higher capital costs than conventional PC plants [3]

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
This could be a new legislative requirement at the State 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 (EMNRD).

*EPA could designate IGCC as a Best Available Control Technology.
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).

[11/1/06] Expansion: *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).

[11/1/06] Expansion: *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
[11/1/06] Expansion: *(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).

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 as the result of an executive order. 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).

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.

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

[1/10/07] 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 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.

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 are presently drafting regulations 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;
- 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), and /or;
    - [1/10/07] Expansion: *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.
[1/10/07] 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.

<u>IV. Background data and assumptions used</u>
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.

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: Mercury Studies for Four Corners Area (Forthcoming)

OVERARCHING: AIR DEPOSITION STUDIES

Mitigation Option: Participate in and Support Mercury Studies

I. Description of the mitigation options:

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 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. 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. Two new studies have begun the region, however. In 2007, the Mountain Studies Institute (MSI) will measure total mercury in bulk deposition, in lake zooplankton (invertebrates eaten by fish), and in lake sediment cores in the San Juan Mountains[8]. Dr. Richard Grossman is measuring mercury levels in hair collected from pregnant women in the Durango vicinity.

Mitigation Option A is 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.

Mitigation Option B is 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.

Mitigation Option C is a 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., Options A and B). 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.html[9]). Costs TBD.

Mitigation Option D is 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.

Mitigation Option E is to continue studies of mercury concentrations in sensitive human populations in the region and 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.

Mitigation Option F is to 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 and administrative.

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 to 2000 levels by the year 2012, 10% below 2000 levels by 2020 and 75% below 2000 levels by 2050. The energy supply technical work group is drafting 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 (2).

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
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 (OCD)
New Mexico Air Quality Bureau
New Mexico Energy, Minerals, and Natural Resources Division

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) CO_2 emissions from Four Corners area power plants (4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV9)
(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) 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 for the EPA Clean Skies Act. The program will cover all fossil fuel-fired boilers and turbines serving an electric generator unit with a nameplate capacity greater than 25 MW and producing electricity for sale, except cogeneration units that produce for sale less than 1/3 of the potential electrical output of the generator that they serve (4). Or, EPA's federal Clean Air Interstate Rule's EGU definition could be used.

The 4C 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 4C 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 4C 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.

[1/10/07] 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
[1/10/07] 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 info
Regulatory agency must be able to enforce rule
Power Plants would continue to look at new ways to reduce emissions

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).

* 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/

4. Electric Generating Units will be defined as it is for EPA Clean Skies Act: For SO_2 and NO_x, the program will cover all fossil fuel-fired boilers and turbines serving an electric generator unit with a nameplate capacity greater than 25 MW and producing electricity for sale, except cogeneration units that produce for sale less than 1/3 of the potential electrical output of the generator that they serve.

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.

<u>Benefits:</u>
"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)."

<u>Tradeoffs:</u> None
<u>Burdens:</u> Administrative costs on regulating agencies, including how to determine state or regional level cap; emissions control upgrade costs or purchasing allowances to power plants

<u>II. Description of how to implement</u>
A. <u>Mandatory or voluntary</u>

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 (2) 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 two continuous ozone monitors. In 2005, the highest 8-hr average ozone levels were observed in the summer. A 70 ppb 8-hr average ozone level was the highest observed at the substation monitor near Waterflow, NM in 2005. A 73 ppb 8-hr average ozone level was the highest recorded at the Bloomfield, NM monitoring station in 2005 (3). *Insert the NM design values*

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.

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 (customize)

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.

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

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

<u>IV. Background data and assumptions used</u>
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.

<u>V. Any uncertainty associated with the option</u>
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.

<u>VI. Level of agreement within the work group for this mitigation option</u>
TBD.

<u>VII. Cross-over issues to the other source groups</u>
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)

Other Sources

Draft Mitigation Option: Phased Construction Projects

I. Description of the mitigation option, including benefits (air quality, environmental, economic, other), tradeoffs (one pollutant for another, etc.) and burdens (on whom, what)

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 revegetation 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 (indicate if assistance is needed from Cumulative Effects and/or Monitoring work groups)

A. Technical – High
B. Environmental – High
C. Economic – High – may result in higher costs for construction projects in some areas.

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

Help from monitoring work group to collect data downwind of

<u>V. Any uncertainty associated with the option</u> (Low, Medium, High) – Low

<u>VI. Level of agreement within the work group for this mitigation option</u>.

<u>VII. Cross-over issues to the other source groups</u> (please describe the issue and which 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 Organizations (Forthcoming)

Mitigation Option: Uniformity of Regulations Between Jurisdictions and as Applied to Construction vs. Sand and Gravel Operations (Forthcoming)

Mitigation Option: Fugitive Dust Mitigation Plan (Forthcoming)

Energy Efficiency, Renewable Energy and Conservation

ENERGY EFFICIENCY, RENEWABLE ENERGY AND CONSERVATION

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: 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
i. 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.

ii. Indicate the most appropriate agency(ies) to implement: Colorado/NM Offices of Energy Management and Conservations,

III. Feasibility of the option
i. 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.
ii. Environmental: The environmental benefits of energy efficiency programs are very well documented.
iii. 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: 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		TOTAL DUE		76.26	
PREVIOUS BILLING PERIOD	34	806	24	2.24		BILLING DATE:		10/20/2006	
SAME PERIOD LAST YEAR	28	676	24	2.72		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				
BILLING INFORMATION:			FROM	TO	PREVIOUS	PRESENT			
METER DEPOSIT	347.00		10/02/06	11/01/06	9750	9845			
PREVIOUS BALANCE			RATE CODE:	36QC					
			USAGE IN CCF:	78					
CURRENT GAS CHARGE TOTAL		85.15	PRESSURE FACTOR:		0.819				
FACILITY CHARGE	21.50			Usage this month		95	therms		
COM LDC COST @ .16000/CCF	12.45			Example of possible cost savings for a gas hot water heater					
UPSTREAM COST @ .02530/CCF	1.97			Most efficient		230		therms/year	
COMMODITY COST @ .67930/CCF	52.86			Anticipated monthly saving in therms				4	kWh
DEFERRED GAS COST @ -.09880/CCF	-7.69			Monthly dollar saving @ your rate of 0.97 cents				3.88	
FRANCHISE FEE @ .05000	4.06			Savings over a 13 year life				605.28	
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							

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

<u>VI. Level of agreement within the work group for this mitigation option:</u> TBD

<u>VII. Cross-over issues to the other Task Force work groups</u>: Unknown

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 Amercian 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.

<u>IV. Background data and assumptions used</u>
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

<u>V. Any uncertainty associated with the option (Low, Medium, High)</u> Low

<u>VI. Level of agreement within the work group for this mitigation option</u> TBD

<u>VII. Cross-over issues to the other Task Force work groups</u> None

Mitigation Option: Four Corners State 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.

IV. Background data and assumptions
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.

V. Any uncertainty associated with the option
This option has lots of uncertainty related to political and legal feasibility.

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

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: 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.

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.

Public utility commission

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: Volunteers do 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.

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: 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 can not 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: 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: Renewable Energy Credits (Forthcoming)

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

II. Description of how to implement

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 4C local utilities and Coops

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.

UL specifications 1741 is used for the intertie invertors. These invertors have precise [

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: 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: 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 nations 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 under utilized 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.

Cumulative Effects

Monitoring

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

- Assess importance of ammonia to visibility
- Visibility modeling would be more accurate if ammonia data were available
- Ammonia emission impacts from NSCR can be better evaluated
- 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

TBD

VII. Cross-over issues to the other source groups

This mitigation option would cross over to the Oil and Gas work group.

Four Corners Area Monitoring Gap Analysis Matrix: Introduction

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 matrix.

Monitoring Programs

All of the air quality programs are represented in the matrix (some sites are under multiple programs) and are listed below. The 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.
- Meteorological conditions required for calculating dry deposition rates.

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.

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.

Distance From

The distances listed refer to the distance from each monitoring site to two representative cities in Colorado and New Mexico. The distances were obtained from Argonne National Lab's interactive Four Corners Aerometric Map. Other "site-to-city" distances can be determined by using this 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).

Key to Matrix Symbols

The following explanation refers to the various symbols used within the matrix cells.

h: Hourly
w: Weekly
x: Parameter is monitored
3w: Every three weeks
1d/3d: Once every three days

Power Plant Stack Requirements

Oil and Gas Equipment Improvements

Four Corners Monitoring Gap Analysis Matrix

Site	Program	Period of Record		Distance from: (Km)		Criteria Pollutants								HAPs
		From	To	Cortez	Durango	O3	SO2	CO	NOx	NO	NO2	PM10	PM2.5	NH3
Substation	SLAMS	01/01/72	Present		73.9	h	h		h	h	H			3w
Bloomfield	SLAMS	08/01/77	Present		59.8	h	h		h	h	H			
Navajo Lake	SLAMS	07/01/05	Present		56.4	h			h	h	H		h	3w
Farmington	SLAMS	08/01/77	Present		66.7							x	x	
S.Ute - Bondad	Tribal	04/01/97	Present		19.3	h			h	h	H	disc 9/30/06		3w
S.Ute - Ignacio	Tribal	06/01/82	Present		25.8	h		h	h	h	H	disc 9/30/06		
Farmington Airport					68.2									3w
Shamrock Site	ARM-FS				34.3	h			h					
Archuleta CO (1act/2)												x	x	
Cortez														
Mesa Verde	CASTNET IMPROVE SPMS NADP/NTN NADP/MDN	1/10/95 03/05/88 ? 04/28/81 12/26/01	Present Present Present Present Present		54.3	h	x		x			1d/3d	1d/3d	3w
Durango Airport														
Durango (3)												2(1/3)11/6)	2(1/3)11/6)	
Durango Mt. Resort	Other											h	h	
3 RAWS no info														
Wolf Creek Pass	NADP/NTN	05/26/92	Present		98.6									
Molas Pass	NADP/NTN	07/29/86	Present		56.4									
Weminuche	IMPROVE	03/02/88	Present		44							1d/3d	1d/3d	
San Pedro Parks	IMPROVE	08/15/00	Present		160.4							1d/3d	1d/3d	
Fort Defiance	Tribal	01/01/99	Present		200.4							x		
Window Rock Airport														
Canyonlands NP	CASTNET NADP/NTN IMPROVE	01/24/95 11/11/97 03/02/88	Present Present Present		214.6	h						1d/3d	1d/3d	
Arches NP	IMPROVE	03/02/88	05/16/92		217.2									
Moab												x		
Gallup														
9 RAWS no info														

		Period of Record		Distance from: (Km)		Criteria Pollutants								HAPs
Site	**Program**	From	To	Cortez	Durango	O3	SO2	CO	NOx	NO	NO2	PM10	PM2.5	NH3
Petrified Forest NP	CASTNET IMPROVE	? 03/02/88	09/17/03 Present		329.2	x						1d/3d	1d/3d	
Rainbow Forest NP	NADP/NTN	12/03/02	Present		274.1									
Alamosa	NADP/NTN				177.6									
Great Sand Dunes NP	IMPROVE	05/04/88	Present		207.1	h						1d/3d	1d/3d	
San Miguel												x	x	

Red letters permit controlled
Blue letters State inventoried
Green background needed for modeling

ARM-FS: Air Resource Management, USDA Forest Service; IMPROVE: Interagency Monitoring of Protected Visual Environments; CASTNET: Clean Air Status and Trends Network, EPA
SLAMS: State/Local Air Monitoring Stations SPMS: Special Purpose Monitoring Stations Tribal: Tribal Jurisdiction NADP/NTN: National Atmospheric Deposition Program, National Trends Network

Site	Meteorological						Deposition									Misc
	Wind	Temp	Delta T	Solar	RH	ppt	Visb	pH	SO4	NH4	NO3	Pb	HF	Hg	Ca,Mg,K,Na,Cl	
Substation	h	h	h	h												
Bloomfield	h	h	h	h												
Navajo Lake	h	h	h	h												
Farmington																
S.Ute - Bondad	x	x		x	x	x										
S.Ute - Ignacio	x	x		x	x	x										
Farmington Airport	x	x	x		x	x										
Shamrock Site	h	h		h	h	h										
Archuleta CO (1act/2)																
Cortez	x	x			x		x									
Mesa Verde	h	h	h	h	h	h	sm	w	w	w	w			w	w	
Durango Airport	x	x			x		x									
Durango (3)																
Durango Mt. Resort	h	h	h	h	h	h	h									
3 RAWS no info																
Wolf Creek Pass								w	w	w	w			w?	w	
Molas Pass							sm	w	w	w	w			w?	w	
Weminuche																
San Pedro Parks																babs
Fort Defiance																
Window Rock Airport	x	x			x		x									
Canyonlands NP								w	w	w	w			w?	w	
Arches NP							x									
Moab																
Gallup	x	x			x		x									
9 RAWS no info																
Petrified Forest NP									w?	w?				w?		babs/bscat
Rainbow Forest NP								w	w	w	w			w?	w	

	Meteorological						Deposition									
Site	Wind	Temp	Delta T	Solar	RH	ppt	Visb	pH	SO4	NH4	NO3	Pb	HF	Hg	Ca,Mg,K,Na,Cl	Misc
Alamosa	x	x			x		x	w	w	w	w			w?	w	
Great Sand Dunes NP																babs
San Miguel																

Red letters permit controlled
Blue letters State inventoried
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Table of Mitigation Options Not Written with Rationale

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	This option will be covered in the Exploration and Production section.
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
Oil and Gas: Exploration & Production (Dehydrators/Separators/Heaters)	Centralized Dehydrators	Already or will be incorporated in other papers on centralization
Oil and Gas: Overarching Issues		
Power Plants		

SECTION	MITIGATION OPTION TITLE	RATIONALE FOR NOT WRITING
Other Sources: Dust		
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