OIL AND GAS GREENHOUSE GAS EMISSIONS REDUCTIONS

STAFF DRAFT REPORT
December 10, 2007

APPENDICES

A. Figure EX-1 and Table EX-1, CCAG Final Report (p. EX-2)

B. CCAG Recommendation ES-12 (Methane Reduction in Oil & Gas Operations (BMPs & PROs)
1) Policy Recommendation (Final Report Appendix H, pp. H-47 to H-50)
2) Summary of Initial Quantification of GHG Savings and Cost per Ton (CCAG Report, Att. H-6)

C. US EPA Gas STAR Program Information
1) List of Gas STAR Emissions Reduction Measures
2) Examples of Gas STAR BMPs and PROs

D. CCAG Recommendation ES-13 (CO2 Reduction from Fuel Combustion in Oil & Gas Operations)
1) Policy Recommendation (Final Report Appendix H, pp. H-51 to H-54)
2) Preliminary Quantification of GHG Savings and Cost per Ton (CCAG Report, Att. H-8)
3) Preliminary Analysis of CO2 Emissions from Natural Gas Fueled vs. Electrically Powered Compressors

E. Climate Change Advisory Group Final Report, Attachment D-2: Fossil Fuel Industry Emissions

F. [Economic Study – Dixon & Chermak, UNM – to be added]

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APPENDIX A

Climate Change Advisory Group Final Report, Figure EX-1 and Table EX-1

Figure EX-1

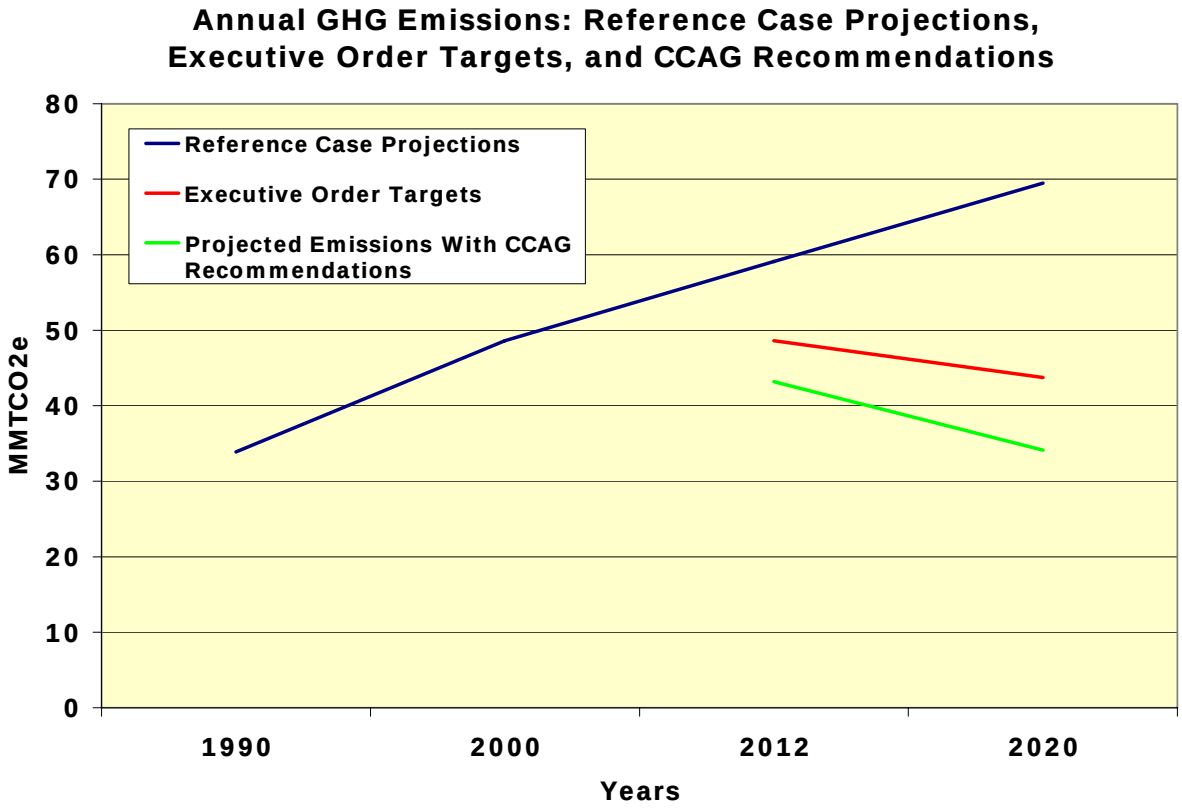

Table EX-1. Annual Emissions: Reference Case Projections, Executive Order Targets, and Impact of CCAG Recommendations

ANNUAL EMISSIONS	1990	2000	2012	2020
REFERENCE CASE PROJECTIONS	33.9	48.6	59.1	69.5
EXECUTIVE ORDER TARGETS [a]			48.6	43.7
GHG REDUCTIONS FROM CCAG RECOMMENDATIONS			*-15.9*	*-35.4*
ANNUAL EMISSIONS WITH CCAG RECOMMENDATIONS			43.2	34.1

[a] Targets aim to reduce New Mexico GHG emissions to 2000 levels by 2012, and 10% below 2000 levels by 2020.

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APPENDIX B

Climate Change Advisory Group Final Report,
Recommendation ES-12 (Methane Reductions in Oil and Gas Operations)

1) Policy Recommendation (CCAG Report App. H, pp. H-47 to H-50)

2) Summary of Initial Quantification of GHG Savings and Cost per Ton (CCAG Report Att. H-6)

ES-12 Methane Reduction in Oil & Gas Operations (BMPs & PROs)

Policy Description:

CCAG Summary: *There are a number of ways in which methane emissions in the oil and gas industry can be reduced. Natural gas consists primarily of methane, so any leaks during production, processing, and transportation/distribution should be addressed. In addition to reducing potent GHG emissions, stopping these leaks may be economically beneficial because it can prevent the waste of valuable product. The EPA Natural Gas STAR program offers numerous methods of preventing leaks. These methods, called Best Management Practices (BMPs) and Partnership Reduction Opportunities (PROs), are divided by industry sub sector (production, processing, and transportation/distribution).*[9]

There are a number of ways in which methane emissions in the oil and gas industry can be reduced. Natural gas consists primarily of methane; therefore, any leaks during production, processing, and transportation/ distribution should be addressed. In addition to reducing GHG emissions, stopping these leaks may be economically beneficial because it can prevent the waste of valuable product.

The EPA Natural Gas STAR program offers numerous methods of preventing leaks. These methods, called Best Management Practices (BMPs) and Partnership Reduction Opportunities (PROs), are divided by industry sub sector: production, processing, and transportation/ distribution. Among the practices recommended are:

Preventive maintenance: Reduces emissions by improving the overall efficiency of the gas production and distribution system; minimizes the chance of leaks.

Reduce flashing losses: As the pressure on the liquid hydrocarbons in a storage tank, well, compressor station, or gas plant drops, some of the lighter compounds dissolved in the liquid are released or "flashed." Some of the compounds that are liquids at the initial pressure/temperature transform from a liquid into a gas/vapor and may be released or "flashed" to the atmosphere. The flashed gas can be captured rather than vented to the atmosphere.

Replace wet seals with dry seals on centrifugal compressors: Dry seals lead to fewer leaks than wet seals. Dry seals use high-pressure gas to seal the compressor and emit less methane, have lower power requirements, improve compressor and pipeline operating efficiency and performance, enhance compressor reliability, and require significantly less maintenance.

Compressor rod & ring replacement on reciprocating compressors: Replacing worn compressor rod packing rings and rods results in operational benefits, reduced methane emissions, and cost savings. Gas leaks from compressor rods may represent one of the largest sources of emissions at natural gas compressor stations.

[9] For a complete list, see http://www.epa.gov/gasstar/techprac.htm#tabnav

Low-bleed, air-based pneumatic devices: Replacing high-bleed devices with low-bleed devices, retrofitting, and improving the maintenance of high-bleed pneumatic devices are proven approaches to profitably reducing methane emissions. Natural gas emissions from pneumatic control devices are one of the largest sources of methane emissions in the natural gas industry.

Pump-down techniques prior to maintenance: Using fixed and portable compressors to lower pipeline pressure prior to maintenance and repair may significantly reduce methane emissions and save money. Pipeline pump-down techniques remove product from the section of pipeline under repair, thereby reducing the volume of natural gas vented to the atmosphere.

Policy Design:

The CCAG recommends that:

Subject to verification of technical and economic feasibility and reduction potential:

(a) New Mexico implement, on a voluntary basis, all BMPs, PROs, and available technologies starting in 2007 to reduce overall CO2e emissions due to methane emissions from the oil and gas sector by ~20% by 2020;

(b) New Mexico actively promote participation by oil and gas operators in EPA's Natural Gas Star program and New Mexico's San Juan VISTAS program; and

(c) As voluntary measures are implemented, if the State determines that oil and gas operators are not on track to achieve the above goal, the State should implement mandatory approaches where appropriate. Mandatory measures would be implemented only after following formal rule making or statutory change procedures with the appropriate "due process" requirements.

- **Goal levels:** As noted above.
- **Timing:** As noted above.
- **Parties:** Oil and gas production, processing, and transportation/distribution companies

Implementation method(s):

Policies to implement these practices could include:

- Information and education.
- Technical assistance.
- Funding mechanisms and/or incentives.
- Voluntary and or negotiated agreements.
- Codes and standards – coupled with cost and investment recovery mechanisms, if appropriate.

Related Policies/Programs in place:

- Some companies practice the measures outlined above, but currently there is no state or federal requirement for any company to implement any of these practices.

Type(s) of GHG Benefit(s):

- CH4: This policy could result in substantial reductions of methane emissions in the oil and gas industry.

Estimated GHG Savings and Costs Per Ton:

The specified goal level is translated into GHG reductions below. BMPs, PROs, and other technologies and practices cover a wide variety of options, the costs of which vary significantly by site and application, and are thus difficult to consolidate. Capital cost and other information for individual technologies and practices is available at EPA's Natural Gas Star website, http://www.epa.gov/gasstar/techprac.htm#tabnav

An initial consolidation analysis of GHG savings and costs per ton was developed by Dr. Lorna Greening to assist in the Energy Supply Technical Work Group's consideration of ES-12. A summary of this spreadsheet can be found in Attachment H-6. The full spreadsheet can be accessed electronically as Attachment H-7 at http://www.nmclimatechange.us/template.cfm?FrontID=4705.

#	Policy	Scenario	Reductions (MMTCO2e)			NPV (2007–2020) $ Millions	Cost-Effective-ness $/tCO2
			2012	2020	Cumulative Reductions (2007-2020)		
ES-12	Methane reductions in oil and gas operations through BMPs and PROs	Specified goals translated into tons GHG reduced.	2.71	3.43	35.34	*Not Estimated*	*Not Estimated*

See the EPA Natural Gas Star website (www.epa.gov/gasstar/techprac.htm#tabnav) and Dr. Lorna Greening's spreadsheet analysis for additional information regarding GHG savings, costs, and cost-effectiveness.

Data Sources, Methods and Assumptions (for quantified actions):

- **Data Sources:** See the EPA Natural Gas Star website (www.epa.gov/gasstar/techprac.htm#tabnav) and Dr. Lorna Greening's spreadsheet analysis for information concerning data sources.
- **Quantification Methods:** See the EPA Natural Gas Star website (www.epa.gov/gasstar/techprac.htm#tabnav) and Dr. Lorna Greening's spreadsheet analysis for additional information.
- **Key Assumptions:** See the EPA Natural Gas Star website (www.epa.gov/gasstar/techprac.htm#tabnav) and Dr. Lorna Greening's spreadsheet analysis for additional information regarding assumptions.

Key Uncertainties:

- See the EPA Natural Gas Star website (www.epa.gov/gasstar/techprac.htm#tabnav) and Dr. Lorna Greening's spreadsheet analysis for additional information regarding uncertainties.

Contributing Issues, if applicable:

- Proportionally more natural gas would get to market rather than being consumed or lost in the production and distribution process.
- Companies increase their sales, and possibly their profits, by selling rather than wasting valuable product.

Feasibility Issues, if applicable:

- Feasibility of specific BMPs and/or PROs vary on a site-by-site basis.

Status of Group Approval:

Complete.

Level of Group Support:

Unanimous consent.

Barriers to consensus (if less than unanimous consent):

None.

Attachment H-6

ES-12 Methane Reductions in Oil and Gas Operations (BMPs & PROs) – Summary of Initial Quantification of GHG Savings and Cost per Ton

The following is a summary of an initial analysis developed by Dr. Lorna Greening to assist in the Energy Supply Technical Work Group's consideration of ES-12. Full details can be found in an accompanying comprehensive spreadsheet. Additional investigation and analysis regarding methane reduction opportunities in oil and gas operations should be conducted to refine and improve this analysis in order to determine GHG reductions, costs or savings, and feasibility associated with reducing methane emissions in oil and gas operations.

The oil and gas participants on the TWG do not agree that the analysis conducted is accurate and reflects correct potential reductions or costs.

Estimated GHG Savings and Costs Per Ton:

#	Policy	Scenario	Reductions (MMTCO2e)			NPV (2007–2020) $ Millions	Cost-Effective-ness $/tCO2
			2012	2020	Cumulative Reductions (2007-2020)		
ES-12	Methane reductions in oil and gas operations through BMPs and PROs	Reduce overall CO2e by ~20% over 2007-2020	2.7	3.4	35.3	-$360.4	-$105

ES-12 Initial Analysis: Summary of Results					
Analysis conducted by Dr. Lorna Greening	Reductions (MMTCO2e)		Cumulative Reductions 2007-2020	NPV (2007-2020) $Millions	Cost-Effectiveness $/tCO2e
	2012	2020			
Distribution					
High with low reduction scenario	0.12	0.14	1.60	-$20.40	-$142.07
Low with high reduction scenario	0.13	0.14	1.64	-$20.02	-$141.92
Transportation					
High with low reduction scenario	0.36	0.62	5.04	-$31.56	-$50.61
Low with high reduction scenario	0.44	0.49	5.56	-$36.49	-$75.00
Gas Processing					
High with low reduction scenario	0.28	0.35	3.66	-$17.56	-$50.48
Low with high reduction scenario	0.28	0.24	3.42	-$15.77	-$65.51
Production					

High with low reduction scenario	1.78	2.35	23.42	-$272.24	-$116.05
Low with high reduction scenario	2.02	2.52	26.33	-$306.70	-$121.67
Overall					
High with low reduction scenario	2.54	3.46	33.72	-$341.76	-$100.39
Low with high reduction scenario	2.87	3.39	36.95	-$378.98	-$110.35
Midpoint of the above two scenarios	2.71	3.43	35.34	-$360.37	-$105.37

Data Sources, Methods and Assumptions (for quantified actions):

- **Data Sources:** See spreadsheet for details.
- **Quantification Methods:** See spreadsheet for details.
- **Key Assumptions:** See spreadsheet for details.

Key Uncertainties:

- See spreadsheet for details.

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APPENDIX C

US EPA Gas STAR Program Information

1) **List of Gas STAR Emissions Reduction Measures**

2) **Example of Gas STAR BMPs and PROs**

Natural Gas STAR Recommended Technologies and Practices - Quantification Methods

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Lessons Learned

From Natural Gas STAR Partners

OPTIONS FOR REDUCING METHANE EMISSIONS FROM PNEUMATIC DEVICES IN THE NATURAL GAS INDUSTRY

Executive Summary

Pneumatic devices powered by pressurized natural gas are used widely in the natural gas industry as liquid level controllers, pressure regulators, and valve controllers. Methane emissions from pneumatic devices, which have been estimated at 31 billion cubic feet (Bcf) per year in the production sector, 16 Bcf per year in the processing sector and 14 Bcf per year in the transmission sector, are one of the largest sources of vented methane emissions from the natural gas industry. Reducing these emissions by replacing high-bleed devices with low-bleed devices, retrofitting high-bleed devices, and improving maintenance practices can be profitable.

Natural Gas STAR partners have achieved significant savings and methane emission reductions through replacement, retrofit, and maintenance of high-bleed pneumatics. Partners have found that most retrofit investments pay for themselves in little over a year, and replacements in as little as 6 months. To date, Natural Gas STAR partners have saved 20.4 Bcf by retrofitting or replacing high-bleed with low-bleed pneumatic devices, representing a savings of $61.2 million. Individual savings will vary depending on the design, condition and specific operating conditions of the controller.

Action	Volume of Gas Saved (Mcf/yr)	Value of Gas Saved ($/yr)[1]	Cost of Imlementation ($)	Payback (Months)
Replacement:				
Change to low-bleed device at end of life.	50 to 200	150 to 600	150 to 250[2]	5 to 12
Early-replacement of high-bleed unit.	260	780	1,350	21
Retrofit	230	690	500	9
Maintenance	45 to 260	135 to 780	Negligible to 350	0 to 5

[1]Cost of gas $3.00/Mcf.
[2]Incremental cost of low-bleed over high-bleed equipment.

This is one of a series of Lessons Learned Summaries developed by EPA in cooperation with the natural gas industry on superior applications of Natural Gas STAR Program Best Management Practices (BMPs) and Partner Reported Opportunities (PROs).

Technology Background

The natural gas industry uses a variety of control devices to automatically operate valves and control pressure, flow, temperature or liquid levels. Control devices can be powered by electricity or compressed air, when available and economic. In the vast majority of applications, however, the gas industry uses pneumatic devices that employ energy from pressurized natural gas.

Natural gas powered pneumatic devices perform a variety of functions in all three sectors of the natural gas industry. In the production sector, an estimated 250,000 pneumatic devices are used to control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. In the processing sector, about 13,000 gas pneumatic devices are used for compressor and glycol dehydration control in gas gathering/booster stations and isolation valves in processing plants (process control in gas processing plants is predominantly instrument air).

In the transmission sector, an estimated 90,000 to 130,000 pneumatic devices actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities. Pneumatic devices are also found on meter runs at distribution company gate stations for regulating flow, pressure, and temperature.

As part of normal operation, pneumatic devices release or bleed natural gas to the atmosphere and, consequently, are a major source of methane emissions from the natural gas industry. The actual bleed rate or emissions level largely depends on the design of the device.

Definition of High-Bleed Pneumatic

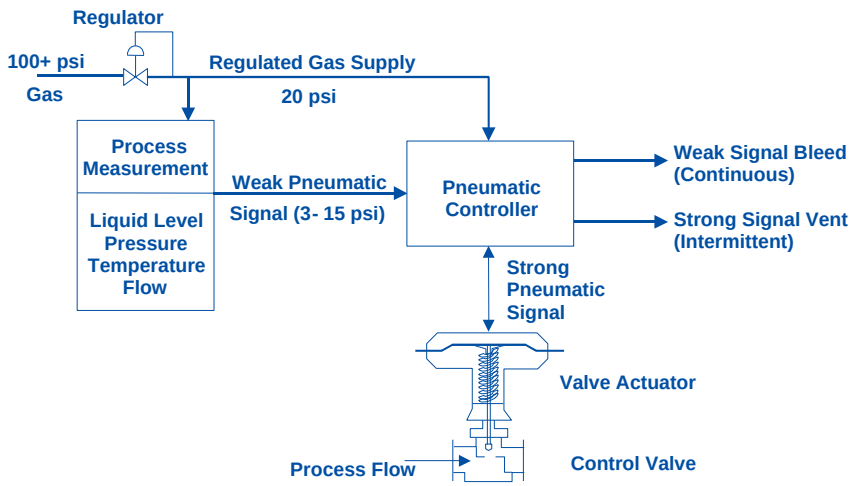
Any pneumatic device that bleeds in excess of 6 scfh (over 50 Mcf per year) is considered a high-bleed device by the Natural Gas STAR Program.

Exhibit 1 shows a schematic of a gas pneumatic control system. Clean, dry, pressurized natural gas is regulated to a constant pressure, usually around 20 psig. This gas supply is used both as a signal and a power supply. A small stream is sent to a device that measures a process condition (liquid level, gas pressure, flow, temperature). This device regulates the pressure of this small gas stream (from 3 to 15 psig) in proportion to the process condition. The stream flows to the pneumatic valve controller, where its variable pressure is used to regulate a valve actuator.

To close the valve pictured in Exhibit 1, 20-psig pneumatic gas is directed to the actuator, pushing the diaphragm down against the spring, which,

through the valve stem, pushes the valve plug closed. When gas is vented off the actuator, the spring pushes the valve back open. The weak signal continuously vents (bleeds) to the atmosphere. Electro-pneumatic devices use weak electric current instead of the weak gas stream to signal pneumatic valve actuation.

Exhibit 1: Pneumatic Device Schematic



In general, controllers of similar design usually have similar steady-state bleed rates regardless of brand name. Pneumatic devices come in three basic designs:

- ★ **Continuous** bleed devices are used to modulate flow, liquid level, or pressure and will generally vent gas at a steady rate;
- ★ **Actuating or intermittent** bleed devices perform snap-acting control and release gas only when they stroke a valve open or closed or as they throttle gas flows; and
- ★ **Self-contained** devices release gas into the downstream pipeline, not to the atmosphere.

To reduce emissions from pneumatic devices the following options can be pursued, either alone or in combination:

1. Replacement of high-bleed devices with low-bleed devices having similar performance capabilities.
2. Installation of low-bleed retrofit kits on operating devices.
3. Enhanced maintenance, cleaning and tuning, repairing/replacing leaking gaskets, tubing fittings, and seals.

Field experience shows that up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment or retrofitted. Exhibit 2 lists the generic options applicable for different controller requirements.

Exhibit 2: Options for Reducing Gas-Bleed Emissions by Controller Type

Action	Pneumatic Types		
	Level Controllers	Pressure Controllers	Positioners/ Transducers
Replacements High-bleed with low-bleed	X	X	X (electro-pneumatic)
Retrofits Install retrofit kits	X	X	X
Maintenance Lower gas supply pressure/replace springs/re-bench	X	X	X
Repair leaks, clean and tune	X	X	X
Change gain setting	X	X	
Remove unnecessary positioners			X

In general, the bleed rate will also vary with the pneumatic gas supply pressure, actuation frequency, and age or condition of the equipment. Due to the need for precision, controllers that must operate quickly will bleed more gas than slower operating devices. The condition of a pneumatic device is a stronger indicator of emission potential than age; well-maintained pneumatic devices operate efficiently for many years.

Economic and Environmental Benefits

Reducing methane emissions from high-bleed pneumatic devices through the options presented above will yield significant benefits, including:

★ **Financial return from reducing gas-bleed losses.** Using a natural gas price of $3.00 per thousand cubic feet (Mcf), savings from reduced emissions can range from $135 to $780 or more per year per device. In many cases, the cost of implementation is recovered in less than a year.

★ **Increased operational efficiency.** The retrofit or complete replacement of worn units can provide better system-wide performance and reliability and improve monitoring of parameters such as gas flow, pressure, or liquid level.

★ **Lower methane emissions.** Reductions in methane emissions can range from 45 to 260 Mcf per device per year, depending on the device and the specific application.

Decision Process

Operators can determine the gas-bleed reduction option that is best suited to their situation, by following the decision process laid out below. Depending on the types of devices that are being considered, one or more options for reducing pneumatic gas bleed may be appropriate.

Five Steps for Reducing Methane Emissions from Pneumatic Devices:

1. Locate and describe the high-bleed devices;
2. Establish the technical feasibility and costs of alternatives;
3. Estimate the savings;
4. Evaluate the economics; and
5. Develop an implementation plan.

Step 1: Locate and describe the high-bleed devices. Partners should first identify the high-bleed devices that are candidates for replacement, retrofit, or repair. The identification and description process can occur during normal maintenance or during a system-wide or facility-specific pneumatics survey. For each pneumatic device, record the location, function, make and model, condition, age, estimated remaining useful life, and bleed rate characteristics (volume and whether intermittent or continuous).

The pneumatic device's bleed rate can be determined through direct measurement or from data provided by the manufacturer. Direct measurement might include bagging studies at selected instruments, high-volume sampler measurements (see "Directed Inspection and Maintenance at Compressor Stations" Lessons Learned) or the operator's standard leak measurement approach. Operators will find it unnecessary to measure bleed rates at each device. In most cases, sample measurements of a few devices are sufficient. Experience suggests that manufacturers' bleed rates are understated, so measurement data should be used when it can be acquired.

Appendix A lists brand, model, and gas bleed information—as provided by manufacturers—for various pneumatic devices. This is not an exhaustive list, but it covers the most commonly used devices. Where available, actual field data on bleed rates are included.

Step 2: Establish the technical feasibility and costs of alternatives. Nearly all high-bleed pneumatic devices can be replaced or retrofitted with lower-bleed equipment. Consult your pneumatic device vendor or an instrumentation specialist

Some high-bleed devices, however, should not be replaced with low-bleed devices. Control of very large valves that require fast and/or precise response to process changes often require high-bleed controllers. These are found most frequently on large compressor discharge and bypass pressure controllers. EPA recommends contacting vendors for new fast-acting devices with lower bleed rates.

for availability, specifications and costs of suitable devices. Low-bleed devices can be requested by specifying bleed rates less than 6 standard cubic feet per hour (scfh). It is important to note that not all manufacturers report bleed rates in the same manner, and companies should exercise caution when making purchases of low-bleed devices.

Appendix B lists cost data for many low-bleed pneumatic devices and summarizes the compatibility of retrofit kits with various controllers. This is not an exhaustive list, but it covers the most commonly used devices.

Maintenance of pneumatics is a cost-effective method for reducing emissions. All companies should consider maintenance as an important part of their implementation plan. Cleaning and tuning, in addition to repairing leaking gaskets, tubing fittings, and seals, can save 5 to 10 scfh per device. Tuning to operate over a broader range of proportional band often reduces bleed rates by as much as 10 scfh. Eliminating unnecessary valve positioners can save up to 18 scfh per device.

Step 3: Estimate the savings. Determine the quantity of gas that can be saved with a low-bleed controller, using field measurement of the high-bleed controller and a similar low-bleed device in service. If these actual bleed rates are not available, use bleed specifications provided by manufacturers.

Gas savings can be monetized to annual savings using $3.00 per Mcf and multiplying bleed reduction, typically specified in scfh, by 8,670 hours per year.

Gas Savings = (High-bleed, scfh) — (Low-bleed, scfh)

Annual Gas Savings = Gas Savings (scfh) * 8,760 hrs/yr * 1 Mcf/1000scf * $3.00/Mcf

Step 4: Evaluate the economics. The cost-effectiveness of replacement, retrofit, or maintenance of high-bleed pneumatic devices can be evaluated using straightforward economic analysis. A cost-benefit analysis for replacement or retrofit is appropriate unless high-bleed characteristics are required for operational reasons.

Exhibit 3 illustrates a cost-benefit analysis for replacement of a high-bleed liquid level controller. Cash flow over a five-year period is analyzed by showing the magnitude and timing of costs (shown in parenthesis) and benefits. In this example, a $380 initial investment buys a level controller that saves

Exhibit 3: Cost-Effectiveness Calculation for Replacement						
Type of Costs	**Year 0**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Implementation Costs, $ (Capital Costs)[1]	(380)					
Annual Savings, $ (New vs. Old)[2]		498	498	498	498	498
Maintenance Costs, $ (New Controller)[3]		(24)	(24)	(24)	(24)	(24)
Avoided Maintenance, $ (Replaced Controller)[3]		50	50	50	50	50
Net Benefit	(380)	524	524	524	524	524
NPV[4] = $1,606 ROI = 138%						

Notes:
[1] Quoted cost of a Fisher 2680 device. See Appendix B.
[2] Annual savings per device calculated as the change in bleed rate of 19 scfh x 8,760 hrs/yr = 167 Mcf/year at $3/Mcf.
[3] Maintenance costs are estimated.
[4] Net Present Value (NPV) based on 10% discount rate for 5 years.

19 scfh of gas. At $3.00 per Mcf, the low-bleed device saves $498 per year. Annual maintenance costs for the new and old controllers are shown. The maintenance cost for the older high-bleed controller is shown as a benefit because it is an avoided cost. Net present value (NPV) is equal to the benefits minus the costs accrued over five years and discounted by 10 percent each year. Return on investment (ROI) is the discount rate at which the NPV generated by the investment equals zero.

Exhibit 4 illustrates the range of savings offered by proven methods for reducing gas bleed emissions. For simplicity, it is assumed that the cost of maintenance of the pneumatic device will be the same before and after the replacement, retrofit, or enhanced maintenance activity.

As seen in Exhibit 4, sometimes more than one option to reduce gas bleed may be appropriate and cost-effective for a given application. For the listed options, please note that the payback period with respect to implementation cost can range from less than one month to two years.

Exhibit 4: Economic Benefits of Reducing Pneumatic Device Emissions					
Action	**Cost[1] ($)**	**Bleed Rate Reductions[2] (Mcf/yr/device)**	**Annual Savings[3] ($/year)**	**Payback Period (Months)**	**Return on Investment[4] (Percent)**
Replacement					
Level Controllers					
High-bleed to low-bleed	380	166	498	9	31
Pressure Controllers					
High-bleed to low-bleed	1,340	228	684	24	42
Airset metal to soft-seat	77	219	657	1.4	>800
Retrofit					
Level Controllers					
Mizer	500	219	657	9	131
Large orifice to small	30	184	552	<1	>1,800
Large nozzle to small	140	131	393	4	>250
Pressure Controllers					
Large orifice to small	30	184	552	<1	>1,800
Maintenance					
All types					
Reduce supply pressure	153	175	525	4	>300
Repair leaks, retune	23	44	132	2	>500
Level Controllers					
Change gain setting	0	88	264	immediate	---
Positioners					
Remove unnecessary	0	158	474	immediate	---

[1]Implementation costs represent average costs for Fisher brand pneumatic instruments installed.
[2]Bleed rate reduction = change in bleed rate scf/hr x 8,760 hr/yr.
[3]Savings based on $3.00/Mcf cost of gas.
[4]Return on investment (ROI) calculated over 5 years.

Exhibit 5: Case Studies on Retrofits To Reduce Gas Leaks at Natural Gas STAR Partner Sites					
Study	**Implementation Costs ($)**	**Emissions Reductions (Mcf/yr)**	**Annual Savings ($/yr)**	**Payback (Months)**	**Return on Investment (%)**
Company 1:					
Platform 1	6,405	2,286	6,858	11	104
Platform 2	9,900	3,592	10,776	11	106
Retrofit Liquid-level controllers	3,885	1,717	5,151	9	131
Company 2:					
Per device	500	219	$657	9	129

The case studies in Exhibit 5 above present analyses performed and savings achieved by two Natural Gas STAR partners who installed retrofit kits at gas production facilities.

Step 5: Develop an implementation plan. After identifying the pneumatic devices that can be profitably replaced, retrofitted or maintained, devise a systematic plan for implementing the required changes. This can include modifying the current inspection and maintenance schedule and prioritizing replacement or retrofits. It may be most cost-effective to replace all those devices that meet the technical and economic criteria of your analysis at one time to minimize labor costs and disruption of operation.

Where a pneumatic device is at the end of its useful life and is scheduled for replacement, it should be replaced with a low-bleed model instead of a new high-bleed device whenever possible.

Other Technologies

Instrument air, nitrogen gas, electric valve controllers, and mechanical control systems are some of the alternatives to gas powered pneumatics implemented by partners.

★ **Instrument Air.** These systems substitute compressed, dried air in place of natural gas in pneumatic devices, and thus eliminate methane emissions entirely. Instrument air systems are typically installed at facilities where there is a high concentration of pneumatic control valves and full-time operator presence (for example, most gas processing plants use instrument air for pneumatic devices). The major costs associated with instrument air systems are capital and energy. Instrument air systems

are powered by electric compressors, and require the installation of dehydrators and volume tanks to filter, dry and store the air for instrumentation use. Generally, partners have found that cost-effective implementation of instrument air systems is limited to field sites with available utility or self-generated electrical power. The Lessons Learned study, "Covert Gas Pneumatic Controls to Instrument Air," provides a detailed description of the technical and economic decision process required to evaluate conversion from gas pneumatic devices to instrument air.

- ★ **Nitrogen Gas.** Unlike instrument air systems that require capital expenditures and electric power, these systems only require the installation of a cryogenic liquid nitrogen cylinder, that is replaced periodically, and a liquid nitrogen vaporizer. The system uses a pressure regulator to control the expansion of the nitrogen gas (i.e., the gas pressure) as it enters the control system. The primary disadvantage of these systems stems from the cost of liquid nitrogen and the potential safety hazard associated with using cryogenic liquids.
- ★ **Electric Valve Controllers.** Due to advances in technology, the use of electronic control instrumentation is increasing. These systems use small electrical motors to operate valves and therefore do not bleed methane into the atmosphere. While they are reliant on a constant supply of electricity, and have high associated operating costs, they have the advantage of not requiring the utilization of natural gas or a compressor to operate.
- ★ **Mechanical Control Systems.** These devices have been widely used in the natural gas and petroleum industry. They operate using a combination of springs, levers, flow channels and hand wheels. While they are simple in design and require no natural gas or power supply to operate, their application is limited due to the need for the control valve to be in close proximity to the process measurement. Also, these systems are unable to handle large flow fluctuations and lack the sensitivity of pneumatic systems.

Each of these options has specific advantages and disadvantages. Where Natural Gas STAR partners do install these systems as replacements to gas powered pneumatic devices, they should report the resulting emissions reductions and recognize the savings.

One Partner's Experience

Marathon Oil Company surveyed 158 pneumatic control devices at 50 production sites using the Hi-Flow Sampler to measure emissions. Half of these controllers were identified as non-bleed devices (e.g. weighted dump valves, spring operated regulators, enclosed capillary temperature controllers, non-bleed pressure switches). High-bleed devices accounted for 35 of 67 level controllers, 5 of 76 pressure controllers, and 1 of 15 temperature controllers. Measured gas emissions were 583 scfh total; 86 percent of emissions came from level controllers, with leaks up to 48 scfh, and averaging 7.6 scfh. Marathon concluded that "control devices with higher emissions can be identified qualitatively by sound prior to leak measurement, making it unnecessary to quantitatively measure methane emissions using technologically advanced equipment."

One Partner's Experience

Union Pacific Resources replaced 70 high-bleed pneumatic devices with low-bleed pneumatic devices and retrofitted 330 high-bleed pneumatic devices. As a result, this partner has estimated a total reduction of methane emissions of 49,600 Mcf per year. Assuming a gas price of $3 per Mcf, the savings corresponds to $148,800. The costs of replacing and retrofitting all the devices, including materials and labor, was $118,500, resulting in a payback period of less than one year.

Lessons Learned

Natural Gas STAR partners offer the following Lessons Learned:

- ★ Hear it; feel it; replace it. Where emissions can be heard or felt, this is a sign that emissions are significant enough to warrant corrective action.
- ★ Control valve cycle frequency is another indicator of excessive emissions. When devices cycle more than once per minute, they can be replaced or retrofitted profitably.
- ★ Manufacturer bleed rate specifications are not necessarily what users will experience. Actual bleed rates will generally exceed manufacturer's specifications because of operating conditions different from manufacturer's assumptions, installation settings and maintenance.
- ★ Combine equipment retrofits or replacements with improved maintenance activities. Do not overlook simple solutions such as replacing tubes and fittings or rearranging controllers.
- ★ The smaller orifices in low-bleed devices and retrofit kits can be subject to clogging from debris in corroded pipes. Therefore, pneumatic supply gas piping and tubing should be flushed out before retrofitting with smaller orifice devices, and gas filters should be well maintained.

- ★ When replacing pneumatic control systems powered by pressurized natural gas with instrument air or other systems, do not forget to account for the savings from the resulting methane emission reductions.
- ★ Include methane emission reductions from pneumatics in annual reports submitted as part of the Natural Gas STAR Program.

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Appendix A

The following chart contains manufacturer-reported bleed rates. Actual bleed rates have been included whenever possible. Discrepancies occur due to a variety of reasons, including:

- ★ Maintenance.
- ★ Operating conditions.
- ★ Manufacturer vs. operating assumptions.

It is important to note that manufacturer information has not been verified by any third party and there may be large differences between manufacturer-reported bleed rates and those found during operations. Until a full set of information is available, companies should be careful to compare bleed rates in standard units (CFH) when comparing manufacturers and models. During this study we found that manufacturers reported information in a wide range of different units and operating assumptions.

Gas Bleed Rate for Various Pneumatic Devices

Controller Model	Type	Consumption Rate (CFH)	
		Manufacturer Data	Field Data (where available)
High-Bleed Pneumatic Devices			
**Fisher 4100 Series	Pressure controller (large orifice)	35	
**Fisher 2500 Series	Liquid-level controllers (P.B. in mid range)	10-34	44-72
*Invalco AE-155	Liquid-level controller		44-63
*Moore Products – Model 750P	Positioner	42	
*Invalco CT Series	Liquid-level controllers	40	34-87
**Fisher 4150/4160K	Pressure controller (P.B. 0 or 10)	2.5-29	
**Fisher 546	Transducer	21	
**Fisher 3620J	Electro-pneumatic positioner	18.2	
Foxboro 43AP	Pressure controller	18	
**Fisher 3582i	Electro-pneumatic positioner	17.2	
**Fisher 4100 Series	Pressure controller (small orifice)	15	
**Fisher DVC 6000	Electro-pneumatic positioner	14	
**Fisher 846	Transducer	12	
**Fisher 4160	Pressure controller (P.B. 0.5)	10-34	
**Fisher 2506	Receiver controller (P.B.0.5)	10	
**Fisher DVC 5000	Electro-pneumatic positioner	10	
**Masoneilan 4700E	Positioners	9	
**Fisher 3661	Electro-pneumatic positioner	8.8	

**Fisher 646	Transducer	7.8	
**Fisher 3660	Pneumatic positioner	6	
**ITT Barton 335P	Pressure controller	6	
*Ametek Series 40	Pressure controllers	6	
Low or No-Bleed Pneumatic Devices			
**Masoneilan SV	Positioners	4	
**Fisher 4195 Series	Pressure controllers	3.5	
**ITT Barton 273A	Pressure transmitter	3	
**ITT Barton 274A	Pressure transmitter	3	
**ITT Barton 284B	Pressure transmitter	3	
**ITT Barton 285B	Pressure transmitter	3	
**Bristol Babcock Series 5457-70F	Transmitter	3	
**Bristol Babcock Series 5453-Model 624-II	Liquid-level controllers	3	
**Bristol Babcock Series 5453-Model 10F	Pressure controllers	3	
**Bristol Babcock Series 5455 Model 624-III	Pressure controllers	3	
**ITT Barton 358	Pressure controller	1.8	
**ITT Barton 359	Pressure controller 1.8	1.8	
**Fisher 3610J	Pneumatic positioner	16	
**Bristol Babcock Series 502 A/D	Recording pneumatic controllers	<6	
**Fisher 4660	High-low pressure pilot	<5	
**Bristol Babcock Series 9110-00A	Transducers	0.42	
Fisher 2100 Series	Liquid-level controllers	1	
**Fisher 2680	Liquid level controllers	<1	
*Norriseal 1001 (A) (Snap)	Liquid-level controller	0.2	0.2
*Norriseal 1001 (A) ('Envirosave')	Liquid-level controller	0	0
*Norriseal 1001 (A) (Throttle)	Liquid-level controller	0.007	0.007
**Becker VRP-B-CH	Double-acting pilot pressure control system (replaces controllers and positioners)	0-10	
**Becker HPP-5	Pneumatic positioner (Double Acting)	0-10	
**Becker EFP-2.0	Electro-pneumatic positioner	0	
**Becker VRP-SB	Single-acting pilot pressure control system (replaces controllers and positioners)	0	

**Becker VRP-SB GAP Controller	Replaces pneumatic “gap” type controllers	0	
**Becker VRP-SB-PID Controller	Single-acting pilot pressure control system specifically designed for power plant type feeds (replaces controllers and positioners)	0	
**Becker VRP-SB-CH	Single-acting pilot pressure control system (replaces controllers and positioners)	0	
**Becker HPP-SB	Pneumatic positioner (Single Acting)	0	
Actuator Model	**Size**	**Manufacturer Data**	**Field Data**
*Shafer RV-Series Rotary Vane Valve Actuators	33” x 32”	1,084	
	36” x 26”	768	
	26” x 22”	469	
	25” x 16”	323	
	20” x 16”	201	
	16.5” x 16”	128	
	14.5” x 14”	86	
	12.5” x 12”	49	
	12” x 9”	22	
	11” x 10”	32	
	9” x 7”	12	
	8” x 6.5”	8	
	6.5” x 3.5”	6	
	5” x 3”	6	
Actuator Model	**Size**	**Number of Snap-acting Strokes per CF**	**Number of Throttling Strokes per CF**
**Fisher Valve Actuators	20	21	39
**Fisher Valve Actuators	30	12	22
**Fisher Valve Actuators	34/40	6	10
**Fisher Valve Actuators	45/50	3	5
**Fisher Valve Actuators	46/50	2	3

* Last updated in 1996.

** Last updated in 2001.

Appendix B

Controllers Compatible with MIZER Retrofits	
Type	**Brand/model Number**
Liquid-level controllers	C.E. Invalco – 215, 402, AE-155
	Norriseal – 1001, 1001A
Pressure controllers	Norriseal - 4300
Suggested Retail Prices for Various Brand Low-Bleed Pneumatic Devices (Estimates Based on Best Information Available at Time of Publication)	
Brand/Model	**Price per Device**
**ITT Barton 335P (pressure controller)	$920
**ITT Barton 273A (pressure transmitter)	$1,010
**ITT Barton 274A (pressure transmitter)	$1,385
**ITT Barton 284B (pressure transmitter)	$1,605
**ITT Barton 285B (pressure transmitter)	$1,990
**ITT Barton 340E (recording pressure controller)	$1,400
**ITT Barton 338E (recorder controller)	$2,800
**Ametek Series 40 (pressure controllers)	$1,100 (average cost)
**Becker VRP-B-CH	$1,575.00
**Becker HPP-5	$1,675.00
**Becker VRP-SB	$1,575.00-$2,000.00
**Becker VRP-SB-CH-PID	$2,075.00
**Becker VRP-SB-CH	$1,575.00
**Becker HPP-SB	$1,675.00
**Mizer Retrofit Kits	$400-$600
**Fisher 67AFR (airset regulators)	$80
**Fisher 2680 (liquid-level controllers)	$380
**Fisher 4195 (pressure controllers)	$1,340
**Bristol Babcock Series 9110-00A (transducers)	$1,535-$1,550
**Bristol Babcock Series 5453 (controllers)	$1,540
**Bristol Babcock Series 5453 40 G (temperature controllers)	$3,500
**Bristol Babcock Series 5457-624 II (controllers)	$3,140
**Bristol Babcock Series 502 A/D (recording controllers)	$3,000
**Bristol Babcock Series 5455-624 III (pressure controllers)	$1,135
**Bristol Babcock Series 5453-624 II (liquid level controllers)	$2,345
**Bristol Babcock Series 5453-10F (pressure controllers)	$1,440

* Last updated in 1996.

** Last updated in 2001.

United States
Environmental Protection Agency
Air and Radiation (6202J)
1200 Pennsylvania Ave., NW
Washington, DC 20460

EPA430-B-03-004
July 2003

OIL AND GAS GREENHOUSE GAS EMISSIONS REDUCTIONS

STAFF DRAFT REPORT
December 10, 2007

APPENDIX D

Climate Change Advisory Group Final Report,
Recommendation ES-13 (CO_2 Reduction from Fuel Combustion in Oil and Gas)

1) Policy Recommendation (CCAG Report App. H, pp. H-51 to H-54)

2) Preliminary Quantification of GHG Savings and Cost per Ton (CCAG Report Att. H-8)

3) Preliminary Analysis of CO_2 Emissions from Natural Gas Fueled vs. Electrically Powered Compressors (CCAG Report Att. H-9)

ES-13 CO2 Reduction from Fuel Combustion in Oil & Gas Operations

Policy Description:

CCAG Summary: There are a number of ways in which CO2 emissions in the oil and gas industry can be reduced, including (1) new efficient compressors, (2) optimize gas flow to improve compressor efficiency, (3) improve performance of compressor cylinder ends, (4) capture compressor waste heat, (5) replace compressor driver engines, and (6) waste heat recovery boilers. Policies to encourage these practices include education and information exchange, financial incentives, and mandates or standards – coupled with cost and investment recovery mechanisms, if appropriate – that require certain practices.

There are a number of ways in which CO2 emissions in the oil and gas industry can be reduced, including (1) new efficient compressors, (2) optimize gas flow to improve compressor efficiency, (3) improve performance of compressor cylinder ends, (4) capture compressor waste heat, (5) replace compressor driver engines, and (6) waste heat recovery boilers.

Given the wide range of costs and technologies involved the CCAG identified three key categories: (1) compressor efficiency improvements, (2) waste heat recovery for compressors and boilers, and (3) replacement of gas-driven compressors with electrical generators. Of these three categories, the focus should be efficiency improvements and waste heat recovery. Compressor replacement was considered a less fruitful area for analysis because (a) new compressors present high costs relative to the GHG reduction potential the provide, and (b) because switching the compressor fuel from gas to electricity simply moves the GHG production – at least in part – to another locale, and evidence indicates that compared to grid average CO2 emissions per kWh at this time, natural gas fueled compressors may emit less CO2 per kWh.[10]

Policy Design:

The CCAG recommends that New Mexico focus attention on reducing GHG emissions from fuel combustion in the oil and gas industry through education, financial incentives, or mandates and/or standards – coupled with cost and investment recovery mechanisms, if appropriate – to: (1) improve the efficiency of compressors; (2) boost waste heat recovery for compressors and boilers including the deployment of CHP systems that could sell excess power back to the grid; and to a lesser extent, (3) replace gas-driven compressors with electrical compressors when doing so reduces CO2 emissions.

The CO2 reduction goals stated below are being provided for the sole purpose of partially meeting the targets set by Governor Richardson's directive and are not necessarily confirmed or validated by any current study or analysis regarding economic or technical feasibility. It is the intent of the CCAG to require further study and analysis of the approaches recommended above by the NMED and other appropriate agencies, and that from this study and analysis, changes in goals and determinations regarding the economic and technical feasibility of these approaches

[10] See Attachment H-9.

may result.

Subject to verification of technical and economic feasibility and reduction potential:

- **Goal levels:** Reduce CO_2 emissions from fuel combustion by 75% by 2020.
- **Timing:** As noted above.
- **Parties:** Oil and gas production, processing, and transportation/distribution companies

Implementation method(s):

Policies to implement these practices could include:

- Information and education.
- Technical assistance.
- Funding mechanisms and/or incentives.
- Voluntary and or negotiated agreements.
- Codes and standards – coupled with cost and investment recovery mechanisms, if appropriate.

Related Policies/Programs in place:

- Some companies may practice the measures outlined above, but there is currently no state or federal requirement for any company to implement any of these measures.

Type(s) of GHG Benefit(s):

- CO2: CO2 emissions would be reduced directly through the implementation of these measures. Methane emissions would also be reduced, but these are addressed in ES-12.

Estimated GHG Savings and Costs Per Ton:

The specified goal level is translated into GHG reductions below. Current uncertainties regarding costs and emission reduction benefits of these approaches inhibit comprehensive and thorough estimation of GHG savings and costs per ton at this time. These shortcomings will be addressed by the NMED-led study referenced in the policy design for ES-13. A preliminary analysis of GHG savings and costs per ton, developed to assist in the Energy Supply Technical Work Group's consideration of ES-13, can be found in Attachment H-8.

#	Policy	Scenario	Reductions (MMTCO2e)			NPV (2007–2020) $ Millions	Cost-Effective-ness $/tCO2
			2012	2020	Cumulative Reductions (2007-2020)		
ES-13	CO2 reduction from fuel combustion in oil & gas operations	Specified goals translated into tons GHG reduced.[11] **(See Attachment H-9)**	.61	1.42	10.63	*Not Estimated*	*Not Estimated*

Data Sources, Methods and Assumptions (for quantified actions):

- **Data Sources**: To be determined by the NMED-led study specified in the ES-13 policy design.
- **Quantification Methods**: To be determined by the NMED-led study specified in the ES-13 policy design.
- **Key Assumptions**: To be determined by the NMED-led study specified in the ES-13 policy design.

Key Uncertainties:

- Data regarding the horsepower, type, location, and grouping of internal combustion engines in New Mexico was not available in time for this analysis. Also, significant uncertainties exist regarding the cost, applicability, and GHG reduction benefits achievable, particularly with respect to grid access (i.e., access to electricity at compressor sites) and cost, as well as the relative CO2 emissions associated with electric vs. natural gas fueled compressors.
- These and other uncertainties are to be identified, determined, and addressed by the NMED-led study specified in the ES-13 policy design.

Contributing Issues, if applicable:

- Proportionally more natural gas may get to market rather than being consumed or lost in the production and distribution process. This could yield a net payback for producers, and negative cost/ton results (i.e., savings).
- Some of the criteria air pollutant emissions that would have resulted from less efficient compressors may be eliminated, lowering health impacts and associated health costs.

[11] Omission of compressor electrification from this total reflects the concern raised in Attachment H-9 that replacing natural gas fueled compressors at this time may not reduce CO2 emissions because of the current carbon intensity of grid average electricity in New Mexico.

- Decreased emissions of criteria pollutants could lead to relaxation of throughput and production limits that may exist in permits, possibly enabling increased production and profits.
- Operation and maintenance costs may be reduced through the use of electric compressors and automated air/fuel ratio controllers.
- Power generation using ORC CHP systems could yield a payback through the sale of electricity and provide additional power for electric compressor engines where grid connections and power purchase opportunities are available.
- Organic Rankine cycle CHP systems do not require water for steam generation and generate no waste, limiting these indirect environmental impacts. Organic Rankine cycle CHP systems may be more feasible than steam driven CHP systems.

Feasibility Issues, if applicable:

- Available data suggests that installation and operation of all scenarios may be feasible to varying degrees. Additional, more detailed, analysis is necessary to quantify the feasibility of these options.

Status of Group Approval:

Complete.

Level of Group Support:

Unanimous consent.

Barriers to consensus (if less than unanimous consent):

None.

Attachment H-8

ES-13 CO2 Reductions from Fuel Combustion in Oil and Gas Operations – Preliminary Quantification of GHG Savings and Cost per Ton

With little industry data and time available, the following cursory analysis was developed by Mr. Jeremy Nichols to assist in the Energy Supply Technical Work Group's consideration of ES-13. Due to these limitations and current uncertainties regarding costs and emission reduction benefits of these and other potential approaches to reduction CO2 from field operations, a comprehensive and thorough estimation of GHG savings and costs (or savings) per ton could not be provided at this time. These limitations, and others as appropriate, will be addressed by the NMED-led study recommended by the CCAG in ES-13.

The oil and gas participants on the TWG do not believe the analysis conducted by Jeremy Nichols is accurate, reflects feasible technologies, or reflects potential opportunities associated with engines located in New Mexico.

Estimated GHG Savings and Costs Per Ton:

#	Policy	Scenario	Reductions (MMTCO2e)			Preliminary	Preliminary
			2012	2020	Cumulative Reductions (2007-2020)	NPV (2007–2020) $ Millions	Cost-Effective-ness $/tCO2
ES-13	CO2 reduction from fuel combustion in oil & gas operations	A. Reduce CO2 emissions by 20% through the use of automated air/fuel ratio controllers on natural gas compressor engines greater than 600 horsepower by 2020.	.3	.6	4.7	-52.9	-$11
ES-13	CO2 reduction from fuel combustion in oil & gas operations	B. Reduce CO2 emissions by 25% using organic Rankine cycle CHP systems at natural gas compressor stations.	.3	.8	5.9	28.0	$5
ES-13	CO2 reduction from fuel combustion in oil & gas operations	C. Reduce CO2 emissions by 30% by replacing natural gas fired compressor engines with electric compressor motors (assuming zero-carbon electricity).	.4	1.0	7.1	-95.5	-$13

ES-13	**CO2 reduction from fuel combustion in oil & gas operations**	**Combination of A, B, and C technology options above.**	**1.0**	**2.4**	**17.7**	**-120.5**	**-$7**
ES-13	**CO2 reduction from fuel combustion in oil & gas operations**	**Combination of A and B technology options above.[42] (See Attachment H-9)**	**0.6**	**1.4**	**10.6**	**-24.9**	**-$2**

Data Sources, Methods and Assumptions (for quantified actions):

- **Data Sources**: U.S. EPA; State of New Mexico; State of Texas; U.S. Climate Change Technology Program; ORMAT International; ControlWorx, LLC; Lazaro et al. (2006) *Strategic Emission Reduction Plan for Stationary Oil and Gas Sources in the Four Corners Region*; Liebowitz and Schochet. (2001) "Generating electric power from compressor station residual heat," *Pipeline and Gas Journal*, November 2001.
- **Quantification Methods**: For all three scenarios, the cost/ton of CO2 reduced was initially calculated using data from government and industry. Cost/ton data was extrapolated from the U.S. EPA, state information, supplier data, and supplier data. CO2 reduction goals were established considering (1) the amount of CO2 that could potentially be reduced, (2) availability of technology, (3) cost, and (4) feasibility (with uncertainties noted below). Natural gas savings were factored into the automated air/fuel ratio controller and electric compressor motor installation scenarios based on Mcf savings data from the EPA and suppliers. Net present value was calculated using a 5% annual discount rate of the total overall costs. Cumulative reductions were determined based on linear progress toward meeting the overall reductions for all three scenarios.

  Based on field studies of the use of automated air/fuel ratio controllers in the Gulf of Mexico and EPA data, CO_2 reductions from the use of such controllers were estimated to average 230.9 tons/year/engine. Automated air/fuel ratio controllers have been suggested as a best management practice in the San Juan Basin.[43]

  Natural gas use savings from the use of an automated air/fuel ratio controller come from more efficient startups, decreased fuel use, and increased production. Average natural gas

[42] Omission of ES-13 Scenario C from this total reflects the concern raised in Attachment H-9 that replacing natural gas fueled compressors at this time may not reduce CO2 emissions because of the current carbon intensity of grid average electricity in New Mexico.

[43] Lazaro et al. (2006) *Strategic Emission Reduction Plan for Stationary Oil and Gas Sources in the Four Corners Region*.

savings of 78 Mcf/day have reported[44], as well as increased production rates of between 1% and 6.8%. Fuel savings could yield a payback of as much as $14,235/year per engine at $5 Mcf. Additional costs of operating an automated air/fuel controller, which include electricity costs, are reportedly offset by the reduction in engine maintenance costs, according to suppliers.[45] The cost of an automated air/fuel ratio controller was estimated to be $120,000, based on data provided by the EPA and suppliers.

Organic Rankine cycle ("ORC") CHP systems have been used at compressor stations in Canada, and are being developed for compressor stations along the North Border pipeline in North and South Dakota, according to industry reports.[46] They are also in use at landfills in Texas and Illinois, where waste heat from flares and reciprocating internal combustion engines is used to fuel ORC systems, according to the EPA.[47] These systems range from 1-10 MW. The cost of installing an ORC system to generate power was estimated at $1,000/kW ($1,000,000/MW), and operation and maintenance costs estimated at $1/MWh, based on supplier and industry data.[48] Overall cost is estimated at $40/MWh of output according to suppliers and field studies.[49]

Estimated annual CO_2 reductions using ORC can reach 6,600 tons of CO_2 reduced per MW installed according to suppliers and industry.[50] This could lead to a 6,600 to 66,000 tons/year reduction in CO_2, depending on the size of the ORC system. Using the midpoint of 36,300 ton/year reduction, this would amount to a $9.17 cost per ton reduction in CO_2 emissions, assuming a total operating time of 8322 hours, which is based on the reported 95% availability of ORC systems.[51]

For electric compressor motor conversion, the cost of conversion comes from the capital cost and operation and maintenance costs. Estimates indicate capital costs for a 1,000 hp engine to be $700,000, with around a $500.00 per day electricity cost according to reports from the state of Texas on the use of electric compressor motors within the state.[52] The use of electric compressor motors has been suggested a best management practice in the San Juan Basin.[53]

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[44] U.S. EPA. (2004) *Automated air/fuel ratio controllers*. PRO Fact Sheet No. 111.
[45] *Supra*.
[46] Liebowitz and Schochet. (2001) "Generating electric power from compressor station residual heat." *Pipeline and Gas Journal*, November 2001.
Western Area Power Administration. (2005). "Exhaust power provides new resource for Basin Electric." *Energy Services Bulletin* 24(6). Available online at http://www.wapa.gov/es/pubs/esb/2005/dec/dec053.htm.
[47] U.S. Climate Change Technology Program. (2005). *Technology Options for the Near and Long Term*. August 2005.
[48] Liebowitz, H.M. (2002). *Generating Electric Power from Waste Heat using ORC Technology*. Power Point Presentation prepared for PTAC 2002 Climate Change and GHG Technology. H.M. Liebowitz, Manager, Heat Recovery Systems, ORMAT International.
[49] *Supra*.
[50] *Supra*, note 3.
[51] *Supra*, note 5.
[52] Texas Comptroller of Public Accounts. (2004). "East Texas gas company looks to cheaper power solution: Powering the pump." *Fiscal Notes*, August 2004.
[53] *Supra*, note 1.

Estimated fuel savings are $1,200/day for a 1,200 hp engine, assuming a natural gas cost of $5/Mcf. Methane emission reductions are reported to be around 2.11 Mcf per year per horsepower converted for electric engines.[54] The replacement of one 3,000 hp compressor engine with an electric compressor is reported to reduce methane emissions by 6,440 Mcf per year.[55] With an average price of natural gas of $5/Mcf, the cost savings average $10.55 per year per horsepower converted. The replacement of one 3,000 horsepower gas-fired engine with an electric compressor could save $32,200/year. Total estimated savings for one 1,000 hp engine are estimated below:

Fuel savings (at $1/hp/day)	Methane emission reduction savings (at 2.11 Mcf/year/hp)	Total daily savings	Total yearly savings
$1,000/day	$28.90/day	$1,028.90	$375,548

Projecting from 2007 to 2020, the total estimated savings of replacing one 1,000 hp engine with an electric compressor are shown below:

Costs/year (with capital cost)	Savings/Year	Net Savings/Year
$236,346	$375,548	$146,382

Assuming an emission rate of 56,100 tons CO2/Mcf, based on EPA AP-42 factors for reciprocating internal combustion engines, and an average throughput of 10,000 Mcf/year, one 1,000 hp compressor engine can release as much as 5,610 tons/year. A payback of $26.09 is estimated for every ton of CO_2 reduced when considering estimated savings.

- **Key Assumptions**: It was assumed that the scenarios above represent the most effective approaches to achieving the policy objective of ES-13. This assumption was based on cost, CO2 reductions, and available data. There may be other effective scenarios, and/or additional information may suggest less effectiveness for above scenarios.

  The above estimates above assume a flat production rate until 2020, i.e, that expanded production efforts will balance out declining production from existing fields. A consistent emission rate of 3.9 MMtCO2/year was assumed based on emission data for field use of natural gas and natural gas processing included in the reference case forecast prepared by Michael Lazarus. A $5/Mcf cost for natural gas was used to estimate savings. Consistent costs across equipment types and sizes were assumed for the purposes of this assessment. It was assumed that the technology required for implementing the scenarios above are readily available and readily adaptable to natural gas production in New Mexico. Other assumptions are as noted above.

Key Uncertainties:

- For automated air/fuel ratio controllers, it is uncertain exactly how many compressor stations could be equipped with this technology and how many controllers would be required. Data

[54] U.S. EPA. (2004). *Install electric compressors*. PRO Fact Sheet No 105.
[55] *Supra*.

regarding the horsepower, type, location, and grouping of internal combustion engines in New Mexico was not available in time for this analysis.

For ORC CHP systems, it is uncertain how many systems would be required and where such systems would be most feasible and effective. Although baseline research and development appears well-developed, additional research and development costs to specifically apply ORC to facilities in New Mexico may arise. It is also uncertain what degree of payback may be expected through the sale of electricity from ORC CHP systems.

For electric compressor motors, it is uncertain what level of feasibility exists within the producing areas of New Mexico and how many compressor engines could be cost-effectively replaced. Data on the availability and accessibility of electric power was not available in time for this analysis. It is also uncertain what the potential costs of transmission line and/or substation construction, if any, and increased power generation would be.

Savings may also vary depending on future natural gas prices and throughput.

Attachment H-9

ES-13 CO2 Reductions from Fuel Combustion in Oil and Gas Operations – Preliminary Analysis of CO2 Emissions from Natural Gas Fueled vs. Electrically Powered Compressors

The following preliminary analysis was developed by Mr. G. Reid Smith to assist in the Energy Supply Technical Work Group's consideration of ES-13. Its conclusion suggests that compared to grid average CO2 emissions per kWh at the present time, fueling a mid-size compressor engine (Caterpillar 3508) with natural gas may result in 32% less CO2 emissions. Similar analyses should be conducted for other size engines and may corroborate this conclusion. Updated emissions information reported by the Natural Resource Defense Council shows "grid average" CO2 emissions of 1.491 lbs/kwh and 1.717 lbs/kwh for PNM and Excel respectively (not restricted to New Mexico) - both of which represent improvement over the 2.02 lbs/kwh figure below, but which remain above the 1.366 lbs/kwh calculated for an engine fueled by natural gas. This may suggest that, at this time, replacement of gas fired engines with electrically driven compressors is a poor idea from a carbon standpoint.

ES-13 Preliminary Analysis of CO2 Emissions from Natural Gas Fueled vs. Electrically Power Compressors				
A.	New Mexico Average Electric Generation; **CO2 lbs/kwh** (Source: EIA, *Updated State-level Greenhouse Gas Emission Coefficients for Electricity Generation 1998-2000*)			2.02
B.	Cat G3508 LE Fuel Usage; BTU/kwh (Source: Derived below as illustrated.)			10,710
C.	Methane; BTU/SCF (Net heating value, i.e., usable BTUs)			909.4
D.	Cat G3508 LE Fuel Usage SCF/kwh (Source: Derived below as illustrated.)			11.777
E.	Cat G3508 LE **CO2 lbs/kwh** (Source: Derived below as illustrated.)			1.366
Derivations:				
F.	11.3	MJ/kwh	From Cat Specification Sheet	
G.	947.82	Btu/MJ	From Google "on-line" conversion tool	
H.	10,710.348	BTU/kwh	Row F time Row G	
I.	11.78	SCF/kwh derived for G3508 LE	Row H divided by Row C	
J.	379.48	SCF/mole		
K.	16.01	MW - methane		
L.	44	MW - CO2		
M.	0.497	lbs methane/kwh		
N.	1.366	lbs CO2/kwh (the ratio of MW's times the methane lbs/hr)	(Row L divided by Row K) time Row M	
Conclusion:				
O.	CO2 Intensity Ratio: Natural Gas Fired Engine to Electric Driven Engine		Row E divided by Row A	**0.68:1**

OIL AND GAS GREENHOUSE GAS EMISSIONS REDUCTIONS

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APPENDIX E

Climate Change Advisory Group Final Report, Attachment D-2:
Fossil Fuel Industry Emissions

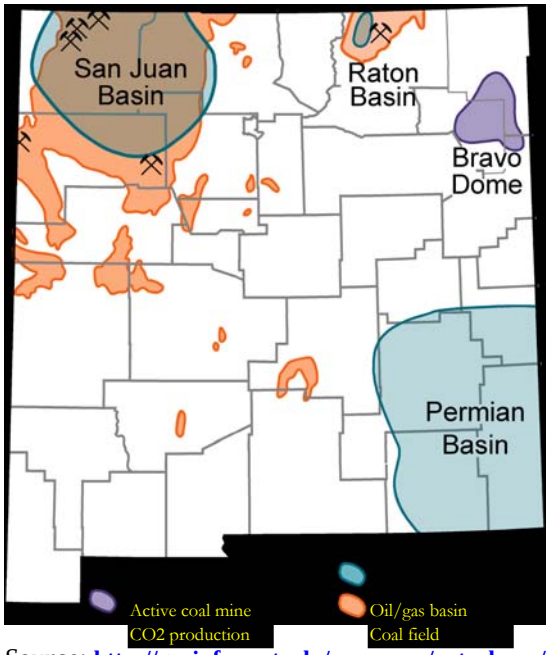
Correction: NMED has been requested by Roger Fernandez, manager of the US EPA Gas STAR program, to provide a correction to Footnote 35, page D-35. Mr. Fernandez indicates that the information attributed to him should state that he estimates total methane emissions by the oil and gas industry in New Mexico to be approximately 20 Bcf.

Attachment D-2. Fossil Fuel Industry Emissions[32]

The oil and gas industry has played an instrumental role in New Mexico's economy and livelihoods for more than 70 years. Oil and gas revenues currently provide about 20% New Mexico's General Fund -- down from historic highs of nearly 90% -- and the industry provides employment for about 10,000 New Mexicans.[33] The State currently ranks second in the nation in natural gas production and fifth in crude oil production.[34] It is also a leader in both the production and reserves of carbon dioxide, which is used largely for enhanced oil recovery.

Natural gas production is concentrated in the northwestern corner of the State (San Juan Basin), while oil production occurs predominantly in the southeast (Permian Basin). (See Figure D-12) As of 2002, over 700 oil and gas industry-related companies operated in the State, working 21,771 oil wells, 23,261 gas wells, 456 CO2 wells, 4,097 enhanced recovery injection wells and 597 salt water disposal wells.[35] In response to expectations of strong US natural gas demands and firm prices, it is expected that another nearly 10,000 gas wells may be drilled in the San Juan Basin in coming years.[36] In addition, there are over 4,500 inactive, non-plugged oil and gas wells that could potentially be returned to production.[37]

Figure D-12. Fossil Fuel and CO2 Producing Regions of New Mexico



Source: **http://geoinfo.nmt.edu/resources/petroleum/**

While coalbed methane (CBM) supplies less than 10% of total US natural gas production, it accounts for nearly a third of New Mexico's natural gas production: 487 of the 1625 billion cubic feet (BCF) produced in 2002.[38] Coalbed methane is found throughout the Rocky Mountain Region, including the Raton and San Juan Basins that span both Colorado and New Mexico. The Fruitland Coal formation of the San Juan Basin is the largest CBM source in the US.

CBM production from the New Mexico portion of the San Juan Basin peaked in 1999 at over 610 Bcf (billion cubic feet), and has since dropped under 500 BCF annually since 2002. At the same time, increased drilling in response to

[32] The Energy Supply Technical Working Group reviewed and accepted the assumptions and results shown in this section.
[33] EMNRD, 2003. *New Mexico's Natural Resources 2003* http://www.emnrd.state.nm.us/Mining/resrpt/default.htm
[34] US DOE Energy Information Agency website. www.eia.gov
[35] ENMRD, 2003.
[36] Bureau of Land Management, 2003. Farmington Resource Management Plan with Record of Decision, December 2003. Farmington Field Office.
[37] EMNRD, 2003
[38] EMNRD, 2003 and data provided separately by the Oil Conservation Division.

expected high demand and prices for natural gas could postpone further decreases in CBM production. Overall, future oil and gas production levels remain highly uncertain, dependent on prevailing oil and gas prices and the potential development of new reserves.

Oil and Gas Industry Emissions

The sheer number and wide diversity of oil and gas activities in New Mexico present a major challenge for greenhouse gas assessment. Emissions of carbon dioxide and methane occur at many stages of the production process (drilling, production, and processing/refining), and can be highly dependent upon local resource characteristics (pressure, depth, water content, etc.), technologies applied, and practices employed (such as well venting to unload liquids which may result in the release of billions of cubic feet of methane annually). With over 40,000 oil and gas wells in the State, three oil refineries, several gas processing plants, and tens of thousands of miles of gas pipelines in the State – and no regulatory requirements to track CO_2 or CH_4 emissions – there are significant uncertainties with respect to the State's GHG emissions from this sector.

At the same time, considerable research – sponsored by the American Petroleum Institute, the Gas Research Institute, US EPA, and others – has been directed towards developing relatively robust GHG emissions estimates at the national level. For the national GHG inventory, US EPA uses a combination of top-down and detailed bottom-up techniques to estimate national emissions of methane from the oil and gas industry (USEPA, 2005). As noted earlier, US EPA has also developed a tool (SGIT) that enables the development of state-level GHG estimates, whereby emissions-related activity levels (numbers of wells, and amount of oil and gas produced) can be multiplied by aggregate emission factors to yield rough estimates of total CH4 emissions. Furthermore, EIA provides estimates of fuel used in New Mexico for natural gas production, processing, and distribution, which enables the estimation of CO2 emissions.

These sources provide a starting point for analysis of New Mexico's oil and gas industry emissions. Additional data and insights have been solicited from industry sources, including the New Mexico Oil and Gas Association (NMOGA) and individual facility managers, US EPA staff, and State agency experts. These sources provided "ground truthing" on several aspects related to State emissions. For example:

- Oil refiners and NMED provided access to permit data that includes estimated fuel consumption. These sources suggest that refinery gas use is over twice the level suggested by EIA data.
- USEPA staff remarked that methane emissions from well venting activities in New Mexico, especially at low pressure CBM sites where the build up of liquids may require venting, appear to be quite significant, perhaps on the order of 40 BCF annually (1.6 million $MMtCO_2eq$).[39]

[39] Personal communication, Roger Fernandez. (It also appears that that some producers have been able modify practices to reduce well venting emissions by about 50%, suggesting a potentially significant source of emission reductions.) This is only one of several significant sources of methane emissions from gas production. The preferred USEPA (SGIT) approach for estimating natural gas production emissions, which involves multiplying national aggregate per well CH4 emissions by the number of New Mexico wells, yields total methane emissions

- NMOGA provided separate estimates for several emissions sources, including carbon dioxide emissions from gas well site equipment (gas combustion in engines, tank heaters, and field separators), and methane and carbon dioxide emissions from venting and flashing activities at field sites. While these data only cover gas production activities in the San Juan Basin, they suggest rates of field gas use (carbon dioxide) and methane emissions that are 50% to 70% higher than the above (EPA-based) estimates. We consider these rates below in a sensitivity analysis.
- Raw gas that emerges from gas and oil wells often contains "entrained" CO_2 in excess of pipeline specifications. This CO_2 is typically separated at gas processing plants and vented to the atmosphere (except in some other states, such as Wyoming and Texas, where it is compressed and transported for enhanced oil recovery).[40] In the case of New Mexico, the CO_2 concentrations of Fruitland CBM are known to be quite significant (currently around 18%), and these concentrations have been rising over time. Data provided by the Oil Conservation Division of EMNRD and NMOGA enable estimates of entrained CO_2 emissions. Though these estimates cover only Fruitland CBM, which accounts for less that a third of New Mexico gas production, it is thought that this is the most significant source of entrained CO2 in the State.
- CO_2 from enhanced oil recovery – In New Mexico, carbon dioxide is extracted from natural formations (Bravo Dome), piped to oil fields, and injected into wells in order to increase yields. Any release of this CO2 during the extraction, transmission, injection, or oil production processes would lead to net emissions to the atmosphere. At the national level, USEPA currently excludes any such emissions from the national inventory, since they are not well understood. In the case of New Mexico practices, NMED is currently looking into available information to assess where any estimates are possible.

Table D-12 provides an overview of the methods used to estimate and project GHG emissions from the various oil and gas sector activities. As shown, a variety of methods were used, in general relying upon local data and guidance from industry and other experts wherever possible.

Several factors will drive future GHG emissions from New Mexico's oil and gas sector, among them:

- Future oil and gas production activity. This is perhaps the most important, yet most uncertain variable that will affect future GHG emissions. One assessment suggests that barring further discovery or development of new reserves, coalbed methane production will remain level for one or two more years, and then begin declining at rate of 13% annually as the fields are depleted.[41] Conventional gas production in the San Juan Basin, under this assessment, would remain flat through the end of the decade, and similarly

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estimates that are significantly less than the national average (per unit natural gas produced), which does not appear justified. Based on discussions with USEPA staff, it was felt that their alternative (SGIT) method – using the New Mexico production-weighted share of national natural gas production methane emissions – would be a better approach for developing initial methane emissions estimates.

[40] On a national level, the USEPA GHG inventory suggests that these entrained CO_2 emissions are quite significant (about 25 MMtCO2in 2002). However, USEPA is still working to systematically incorporate this emissions source into the national inventory, given concerns about double counting emissions in locations (outside New Mexico) where this CO_2 may be used for enhanced oil recovery.

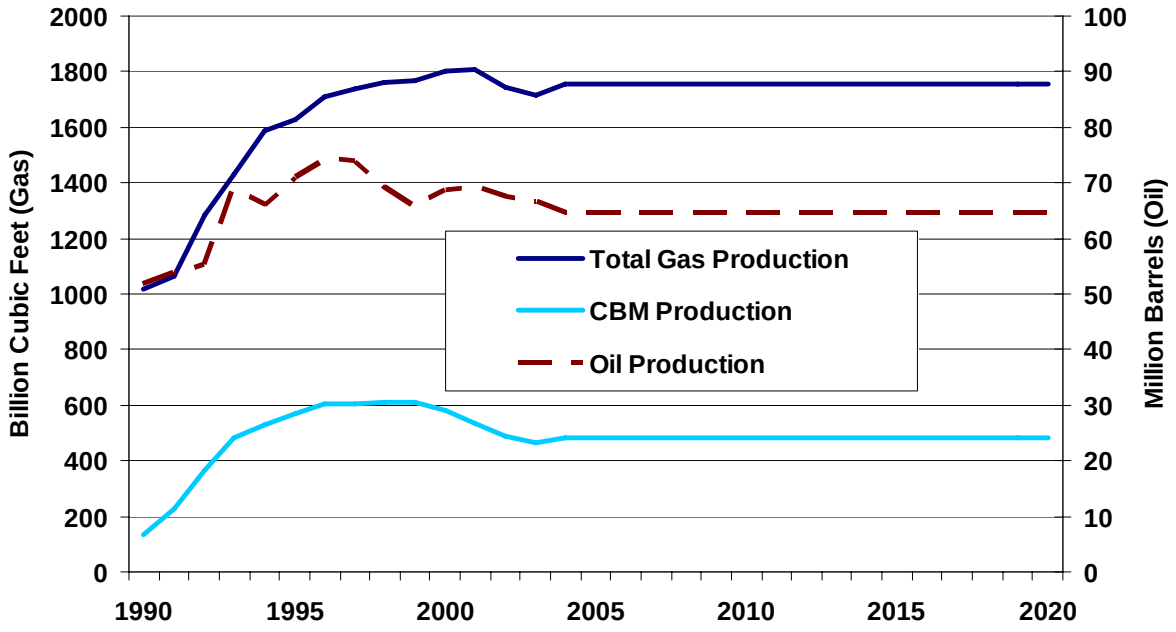
[41] Bernstein Research Call, May 27, 2005.

begin declining at 13% per year. (This assessment covered only the San Juan Basin)

Not surprisingly, there are many competing views on the future of oil and gas production, and prognostications of declining production have been made in the past. Total statewide natural gas production has been relatively steady from 1997 to 2004, varying by less than 6% over this 8-year time period. Thus another possible scenario is that additional reserves are found and exploited such that production remains constant through 2020. The Energy Supply Technical Working Group evaluated the differing views on future oil and gas production and came to the conclusion that the most likely was that emissions remain constant in the sector, and this assumption was used in preparing this inventory.

The implications of this assumption in terms of oil and gas production are depicted in Figure D-13 below.

Figure D-13. Future Oil and Gas Production



- Number of operating wells. As many of the oil and gas fields play out, more operating wells may be needed to maintain production levels. Some emissions, fugitive methane in particular, may depend on the number of operating wells as much as on total oil and gas production. The projected increase in the number of operating wells is based on the estimates contained in the BLM's Resource Management Plan for the San Juan Basin. Note that this estimate will likely need to be adjusted to correspond to the oil and gas production scenario chosen above.

- Changes in production, processing, and pipeline technologies and practices. In response to industry and USEPA emission reduction initiatives (e.g. GasStar), as well as

technological advancements, progress has been made in lower GHG emissions per unit of oil and gas produced and delivered. Further improvements are likely, but have not been estimated for this initial analysis.

Key assumptions are noted in Table D-11.

Table D-11. Key Assumptions for the Oil and Gas Sector Projections

Parameter	Assumption
Natural Gas and Oil Production	Flat oil and gas production through 2020 See text for details
Oil Refinery Production	No changes in refinery activities (or emissions) are presently assumed.
GHG emissions per unit input/output	Potential emissions savings particularly for methane could be considerable, but are not considered here due to lack of information.

Coal Production Emissions

Methane occurs naturally in coal seams, and is typically vented during mining operations for safety reasons. This methane is typically referred to as "coal mine methane" in contrast coal bed methane, which is associated with coal seams (such as Fruitland) that are not expected to be mined.

Historical coal mine methane emissions were estimated using the EPA SGIT tool, which multiplies coal production times an average emission factor, depending on the mine type. Coal mine methane emissions are considerably higher, in general, per unit of coal produced, from underground mining than from surface mining.

As of 2003, six surface mines were operation in New Mexico. In 2001, underground operations commenced at the San Juan coal mine, and since then surface operations at one other mine (Ancho) has been significantly curtailed. The increasing share of underground coal in recent years has led to an increase in estimated coal mine methane emissions from about 0.2 MMtCO2e to 0.7 MMtCO2e.

Future coal mine methane emissions will depend on the extent to which operations continue to move underground (which could increase emissions significantly) and/or new coal mining operations change in response to demands from the power market. No effort has yet been made to estimate these potential changes.

Table D-12. Emissions Sources and Estimation Methods for the Oil and Gas Sector

Activity	Emissions Source	Approach to Estimating Historical Emissions	Projection Approach
Natural Gas Drilling and Field Production	CO_2 from field use of natural gas	EIA data	Changes with number of operating wells. (CH_4 emissions savings due to further NG Star activity not considered).
	CH_4 from leaks, venting, upsets, etc.	NM share of national emissions (based on total production). EPA staff separately estimate 40 BCF CH_4 (1.6 MMtCO2e) could result from well venting alone.	
Natural Gas Processing	CO_2 from fuel use in gas processing	EIA data	Changes with total statewide gas production or for the case of entrained CO2, with Fruitland gas production. CO_2 concentrations of Fruitland CBM are assumed to increase based on recent trends.
	CO_2 released fro entrained CO_2	Based on NMOGA estimates of CO2 concentration, and NM Oil Conservation Division estimates of gas production, for the Fruitland CBM field. No estimates made for other gas production sources.	
	CH_4 from leaks, venting, upsets, etc.	NM share of national emissions (based on state vs. US production)	
Natural Gas Transmission and Distribution	CO_2 from fuel use (pumps, compressors)	EIA data	Distribution emissions grow with state gas consumption. No changes currently assumed for transmission-related emissions. Could decrease due to further NG Star activity.
	CH_4 from leaks, venting, upsets, etc.	NM share of transmission & distribution national emissions, based on NM share of national transmission line mileage (transmission) and natural gas consumption (distribution)	
Oil Production	CO_2 from fuel use	EIA data	Grows with state oil production.
	CH_4 from leaks, venting, upsets	SGIT tool.	
Oil Refining	CO_2 from on-site fuel use (refinery gas and natural gas)	Based on fuel use and capacity as reported to NMED in permit data. No annual variations considered.	Grows with oil refinery output.
	CH_4 from leaks and combustion	SGIT tool (included with production above)	
Oil Transport	CO_2 from field use of natural gas	No estimates available	Grows with state oil production.
	CH_4 from combustion	SGIT tool (included with production above)	
Carbon Dioxide Production	CO_2: Fugitive Losses	Not included/no information available.	n/a
	CO_2: Enhanced Oil Recovery	Not yet estimated	n/a
	CO_2: Other uses (shown with industrial process emissions)	Production data. Assume only 1% is for non-oil recovery applications (EMNRD as cited in USEPA, 2005).	No changes assumed.

Overall Results

The resulting emissions estimates for the fossil fuel industry are shown in Table D-13 below. As shown, total fossil fuel industry emissions are quite significant, increasing from 15 to nearly 20 MMtCO2e during the 1990s, largely as the result of increased gas production, and in particular of coalbed methane, which led to an increase in the release of entrained carbon dioxide by over 4 MMtCO2. As shown in this table, GHG emissions would likely remain near 2000 levels through 2020, assuming no new and major efforts to reduce fuel use and/or emissions.

Table D-13. Emissions Estimates for the Oil and Gas Sector, by Source and Gas, 1990-2020 (Scenario A)

(Million Metric Tons CO2e)	1990	2000	2010	2020	Explanatory Notes for Projections
Fossil Fuel Industry	**15.2**	**19.5**	**20.3**	**20.7**	
Natural Gas Industry	**12.7**	**17.0**	**17.3**	**17.7**	
Production					
Fuel Use (CO2)	1.8	2.0	1.9	1.9	grows with gas production
Methane Emissions (CH4)	1.9	3.4	3.7	3.7	grows with gas production
Processing					
Fuel Use (CO2)	1.9	2.1	2.0	2.0	grows with gas production
Methane Emissions (CH4)	0.8	0.8	0.9	0.9	grows with gas production
Entrained Gas (CO2)	0.8	5.0	5.2	5.6	grows with CBM prod & CO2 concentration
Transmission					
Fuel Use (CO2)	4.2	2.3	2.3	2.3	no change assumed from 2003 on
Methane Emissions (CH4)	1.0	0.9	0.9	0.9	no change assumed from 2003 on
Distribution					
Fuel Use (CO2)					included in transmission (above)
Methane Emissions (CH4)	0.4	0.4	0.3	0.4	grows with gas consumption
Oil Industry	**2.3**	**2.3**	**2.3**	**2.3**	
Production					
Fuel Use (CO2)					included in industrial oil use (above)
Methane Emissions (CH4)	0.7	0.7	0.7	0.7	grows with oil production
Refineries					
Fuel Use (CO2)	1.6	1.6	1.6	1.6	assumes no major changes
Methane Emissions (CH4)					included in oil production (above)
Coal Mining (Methane)	**0.2**	**0.2**	**0.7**	**0.7**	no change assumed from 2003 on

These results as noted earlier are highly sensitive to several assumptions, most notably emissions rates associated with natural gas production activities and future trajectories for oil and gas production. If the emissions rates estimated by NMOGA for oil and gas activities in the San Juan Basin (in 2002) are assumed to apply for all gas production activities in the State, then natural gas production emissions would be about 3 to 4 MMtCO2e higher than shown in Table D-13.[42]

[42] Estimated emissions for 2002 (not shown) would be 2.5 MMtCO2e higher for methane, and 0.9 MMtCO2e higher for carbon dioxide.

Major Uncertainties and Other Issues

The uncertainties in emissions for the fossil fuel industry are perhaps more significant than in any sector other than forestry. Methane emissions and entrained carbon dioxide emissions in gas production and processing represent over half of these emissions. However, these emissions are not directly monitored and can only be estimated using industry assumptions. Field practices can vary considerably, e.g. with respect to flashing and venting, depending on the operator and the resource involved, and there is no monitoring of these practices. There are also significant with respect to methane emissions in transmission and distribution systems, since there is no systematic monitoring and emissions from venting and leaks can vary considerably from site to site.

In addition, significant uncertainties remain with respect to:

- The quality of historical data on field, processing, and pipeline use of natural gas.
- CO2 emissions from enhanced oil recovery, which have not been estimated.
- Refinery fuel use. EIA indicates less than half the refinery fuel use as indicated by refinery permit data.
- Coal mine methane. More accurate estimates would require mine-specific measurements.

Description of Sources of Methane emissions in the Oil and Gas Industry
Excerpted from the US national GHG inventory (USEPA, 2005)

Petroleum Systems

- *Production Field Operations*. Production field operations account for over 95 percent of total CH_4 emissions from petroleum systems. Vented CH_4 from field operations account for approximately 83 percent of the emissions from the production sector, fugitive emissions account for six percent, combustion emissions ten percent, and process upset emissions barely one percent. The most dominant sources of vented emissions are field storage tanks, natural gas-powered pneumatic devices (low bleed, high bleed, and chemical injection pumps). These four sources alone emit 79 percent of the production field operations emissions. Emissions from storage tanks occur when the CH_4 entrained in crude oil under pressure volatilizes once the crude oil is put into storage tanks at atmospheric pressure.
- *Crude Oil Transportation.* Crude oil transportation activities account for less than one percent of total CH_4 emissions from the oil industry.
- *Crude Oil Refining*. Crude oil refining processes and systems account for only three percent of total CH_4 emissions from the oil industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the refineries.

Natural Gas Systems

- *Field Production*. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, gathering pipelines, and well-site gas treatment facilities such as dehydrators and separators. Fugitive emissions and emissions from pneumatic devices account for the majority of emissions. Emissions from field production accounted for approximately 34 percent of CH_4 emissions from natural gas systems in 2003.
- *Processing*. In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in "pipeline quality" gas, which is injected into the transmission system. Fugitive emissions from compressors, including compressor seals, are the primary emission source from this stage. Processing plants account for about 12 percent of CH_4 emissions from natural gas systems.
- *Transmission and Storage*. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the United States transmission system. Fugitive emissions from these compressor stations and from metering and regulating stations account for the majority of the emissions from this stage. Pneumatic devices and engine exhaust are also sources of emissions from transmission facilities. Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these storage facilities. Methane emissions from transmission and storage sector account for approximately 32 percent of emissions from natural gas systems.
- *Distribution*. Distribution pipelines take the high-pressure gas from the transmission system at "city gate" stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. Distribution system emissions, which account for approximately 22 percent of emissions from natural gas systems, result mainly from fugitive emissions from gate stations and non-plastic piping (cast iron, steel). An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced the growth in emissions from this stage.

OIL AND GAS GREENHOUSE GAS EMISSIONS REDUCTIONS

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APPENDIX F

[Economic analysis, D. Dixon & Dr. J. Chermak (UNM) – to be added]

Correction: NMED has been requested by Roger Fernandez, manager of the US EPA Gas STAR program, to provide a correction to Footnote 35, page D-35. Mr. Fernandez indicates that the information attributed to him should state that he estimates total methane emissions by the oil and gas industry in New Mexico to be approximately 20 Bcf.