The Economics of New Mexico Natural Gas Methane Emissions Reduction

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"*NMED shall conduct a study of voluntary and mandatory mechanisms for reducing greenhouse gas emissions from oil and gas processes by January 1, 2008 and shall submit such study to the Team, the Clean Energy Development Council, and the Governor by said date. Proposed mechanisms shall reduce methane emissions in oil and gas operations by 20% by 2020 and carbon dioxide emission from fuel combustion.*"

(Executive Order 2006-69)

Executive Summary

The Governor's goal of a 20% reduction of methane emissions from oil and gas operations by 2020 is economically feasible. Given current industry characteristics, the estimated methane emission level from the New Mexico natural gas industry is approximately 5.8 million metric tons of CO_2 equivalent. In order to meet the Governor's goal, a reduction of 1.16 million metric tons is necessary by 2020. All segments of the industry contribute, with production being responsible for 64%, processing and transmission being responsible for approximately 15.5% each, and distribution contributing about 5% of total emissions. A variety of programs could be implemented to meet the 2020 goal; however the costs and impacts of the various alternatives are not equal. This report provides an assessment of the impacts of the four natural gas industry segments, as well as a more in-depth analysis of the production segment, the largest contributor of methane emissions. This study finds that with strategies combining clean new wells, retired inefficient wells, and retrofitted high-gas-volume wells, a variety of outcomes may achieve the required goal with a minimal negative economic impact. Specifically, within just the production segment, by the year 2020:

- Shutting in of old natural gas wells may reduce total methane emissions by 6.3%
- With required clean technology on all future wells, an average of 1500 new wells per year will increase total methane emissions by 4.8%, for a net decrease in total methane emissions of 1.5%
- Retrofitting existing gas wells with new technology may reduce total methane emissions by up to 12.8%

The economically appropriate mix of these strategies will depend on trends in natural gas prices: lower gas prices will reduce the number of new wells coming on line and will force more low-efficiency wells to be shut in. This scenario will have to rely heavily on retrofitting. Alternatively, higher gas prices will stimulate new production, but will allow more low-efficiency wells to stay in production. Although this scenario will benefit more from new low-emission wells, reliance on retrofitting will depend on trends in total production levels.

The requirement for clean technologies on new wells is a clear opportunity for regulation. Retrofitting existing wells is a clear candidate for an incentive market-based approach. Combined pressures from the natural gas market and an emissions-credit market may speed the retirement of low-efficiency wells.

Within the other segments, significant reductions are also possible through directed inspection and maintenance (DI&M) programs:

- Up to 11% reduction in total methane emissions from reduced processing segment leaks
- Up to 13% reduction in total methane emissions from transmission segment compressors
- Up to 0.6% reduction in total methane emissions from distribution segment meter and pressure regulating stations

These remediations are cost effective for wellhead prices down to $4.57 per Mcf, or with recovered gas as low as 74% of GasSTAR estimates.

Various incentive and regulatory options are available to accomplish these strategies. Improved data collection will be very important to the selection of appropriate strategies in terms of both economic impact and implementation effectiveness. Collection of consistent and timely methane production and emission data is the first and most urgent task in the success of this program.

1.0 **Introduction**

The New Mexico Climate Change Advisory Group (CCAG) recognized that there are a number of ways in which reduced methane emission levels can be achieved. The CCAG Final Report (CCAG 2006) cites the Natural Gas STAR Program of the U.S Environmental Protection Agency (EPA-GasSTAR), which documents Best Management Practices (BMPs) and Partnership Reduction Opportunities (PROs) that can reduce methane venting and leaks in the production, processing, transmission and distribution segments of the natural gas industry.

In regards to reducing CO_2 emissions the CCAG Final Report again recognizes that these reductions could come from a number of areas including (1) installing new efficient compressors, (2) replacing compressor driver engines, (3) optimizing gas flow to improve compressor efficiency, (4) improving performance of compressor cylinder ends, (5) capturing compressor waste heat, and (6) utilizing waste heat recovery boilers (CCAG 2006). Furthermore, the CCAG Final Report recommends GHG emissions reductions be achieved through education, financial incentives, mandates and/or standards – coupled with cost and investment recovery mechanisms, if appropriate.

In order to ascertain the best incentive mechanisms to achieve the goals set forth by Executive Order 2006-69 and minimize the social impact, a thorough economic assessment is necessary. This report provides a starting point for such an analysis. Specifically the report:

- Provides an overview of the contributors from each segment within the natural gas industry from wellhead to delivery. The segments include; production, processing, transmission, and distribution. This overview is presented in Section 2
- Provides a more in-depth analysis of production, the natural gas industry segment which contributes the majority of methane emissions. The analysis of the production segment is included in Section 3.

- Provides an overview of potential incentive schemes, which is presented in Section 4.

Finally, Section 5 presents conclusions as well as considerations for additional research.

2.0 Principal Contributors to Natural Gas Emissions

CCAG forecasts of New Mexico natural gas emissions by each of the four segments – production, processing, transmission, and distribution – are shown in Table 1 and graphically in Figure 1, which juxtaposes the contribution of methane (CH_4) to direct carbon dioxide (CO_2) emissions by each segment. The relative importance of each segment to methane emissions is readily apparent in Figure 2. Note that the table presents the impact of methane in terms of an equivalent amount of carbon dioxide. The total volume of methane emissions is actually much less than that of carbon dioxide, but the global warming potential of methane is about 21 times that of carbon dioxide (EPA-Methane).

Table 1 – Forecast New Mexico greenhouse gas emissions by the natural gas industry for 2010 (CCAG 2006)

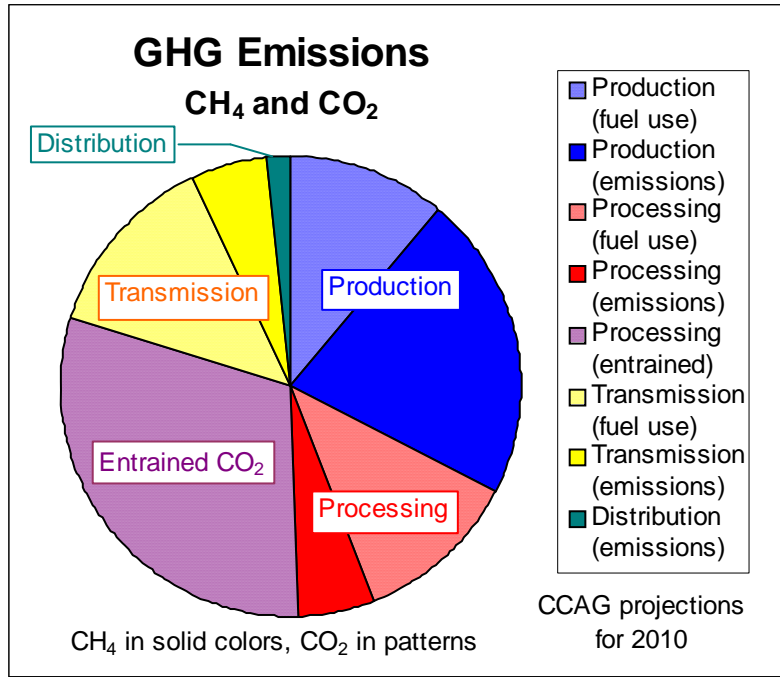| Natural Gas Production Greenhouse Gas Emissions 2010 forecast in millions of metric tons CO_2 equivalent			
Segment	**Methane emissions**	**CO_2 emissions / source**		**Total**
Production	3.7	1.9	fuel use	5.6
Processing	0.9	2.0	fuel use	
		5.2	entrained gas	8.1
Transmission	0.9	2.3	fuel use	3.2
Distribution	0.3			0.3
Total	**5.8**	**11.4**		**17.2**

Source: (CCAG-Emissions)

The CCAG Final Report includes a top-down inventory in which current emission estimates were allotted to industry segments based on EPA historical distributions. Thus, the actual level of emissions by each segment, or by each emission source within a segment, is not actually measured or reported.

The composition of each industry segment is quite distinct. The production segment in New Mexico is comprised of 506 firms[1]. As such, the producers do not, in general exercise market power and may be considered price takers. However, even within this segment there is substantial variation in producer size.

The processing segment in New Mexico includes 13 firms operating 25 natural gas processing plants (NMED-Plants). Processors hold geographic semi-monopolies and are subject to some government regulation.

The transmission segment in New Mexico has five participating firms. The transmission firms are considered common carriers (pursuant FERC Order 636, as well as subsequent orders) and may or may not be subject to market powers.

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[1] Data in the section are from 2006, taken from the downloaded OCD database (OCD 2007)

Figure 1– Forecast greenhouse gas emissions by the New Mexico natural gas industry for 2010. Source (CCAG 2006)
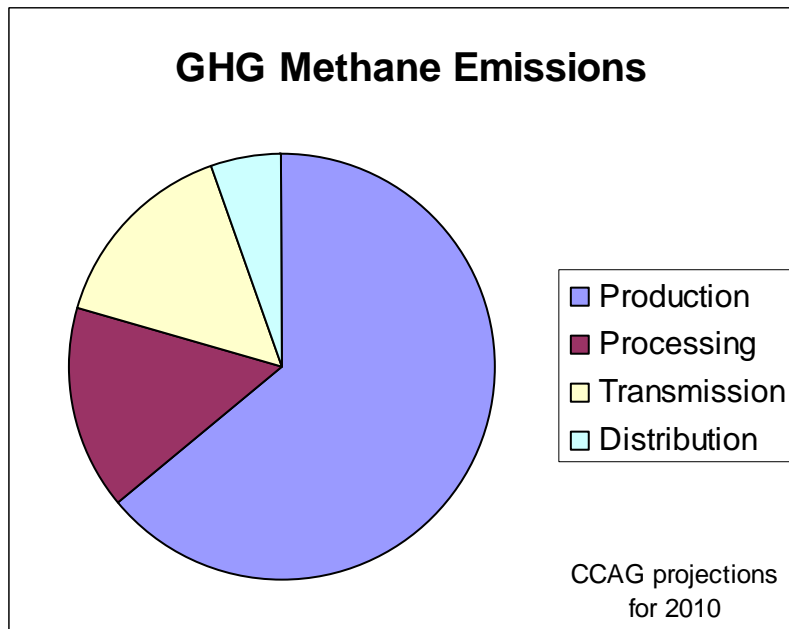
Figure 2 – Forecast methane emissions by the New Mexico natural gas industry for 2010. Source (CCAG 2006).

There are 19 distribution firms in New Mexico: one is tribally owned, one is investor owned, two are privately owned, and 15 are municipally owned. Distribution companies are geographic monopolies and subject to regulation by the State.

The differences and distinct activities of each segment are discussed in more detail in the following sections.

2.1 Natural Gas Production

The production segment contributes nearly 64% of total methane emissions by the New Mexico natural gas industry (see Table 1.) There are three types of natural gas production employed in New Mexico:

> *well gas* - wells producing principally natural gas
> *casinghead gas* – wells producing principally oil with natural gas as a by-product
> *coalbed methane* – (CBM) coal seams producing natural gas with prodigious quantities of entrained carbon dioxide

Additionally, there are three geographic areas of natural gas production in New Mexico, the Raton Basin in the northeast corner of the state, the San Juan Basin in the northwest of the state, and the Permian Basin in the southeast. All three types of wells are found in the San Juan Basin, only CBM wells are in the Raton Basin, and only well gas and casinghead gas are found in the Permian Basin. The number of wells of each type in each county is portrayed graphically in Figure 3. Figure 4 shows the annual gas volume by each type of well for each county. These data are summarized in Table 2.
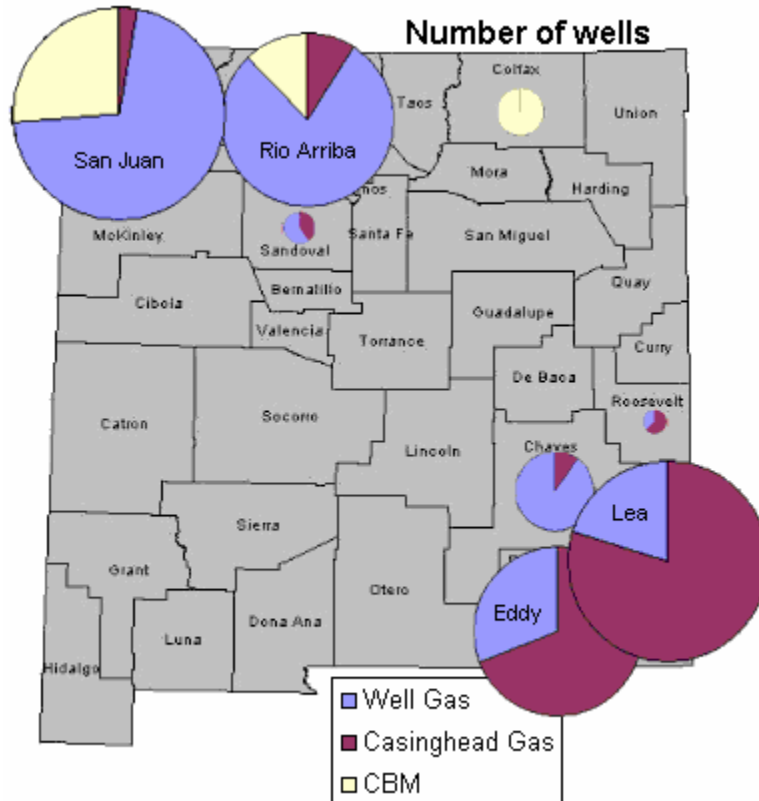
Figure 3 – Gas production by number of wells. Areas are proportional to the number of wells in each county in 2006. Data source (OCD 2007). GIS source (UNM-IARS).
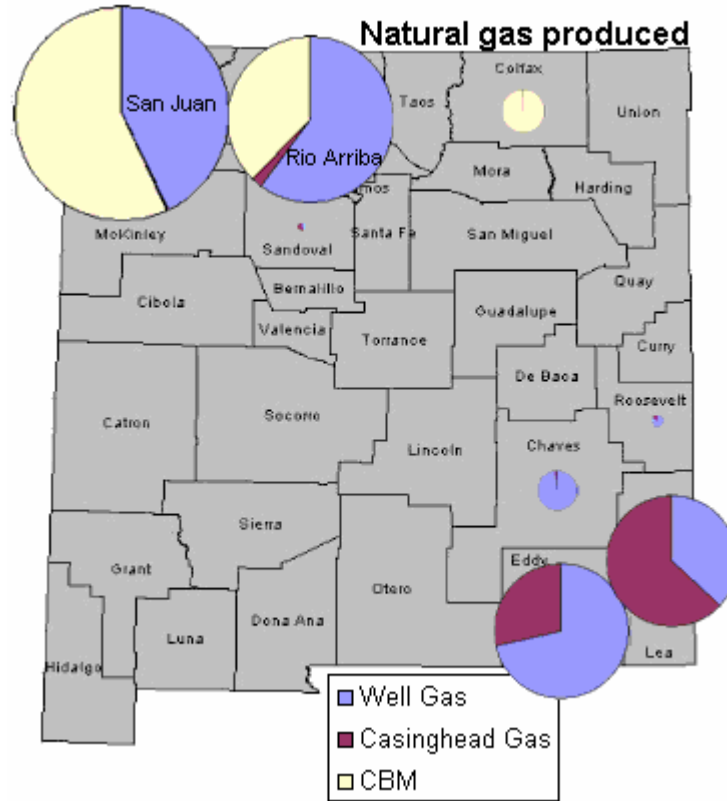
Figure 4 – Well types by volume. Areas are proportional to the 2006 production volume in each county. Data source (OCD 2007). GIS source (UNM-IARS).

Table 2 – Gas production statistics by county.

County	Well gas		Casinghead gas		Coal bed methane (CBM)	
	# of wells	Volume (MMcf)	# of wells	Volume (MMcf)	# of wells	Volume (MMcf)
Chaves	1401	22,933	151	292	0	0
Colfax	0	0	0	0	573	26,393
Eddy	2306	171,506	5120	68,743	0	0
Harding	1	35	0	0	0	0
Lea	2108	87,986	8217	150,838	0	0
Rio Arriba	6049	221,238	704	8,316	942	138,646
Roosevelt	59	2,025	98	407	0	0
San Juan	8085	262,469	327	2,107	3033	349,026
Sandoval	163	517	110	664	1	4

Source: (OCD 2007)

With large variations from well to well, gas at the wellhead may contain large amounts of oil, typical of casinghead gas, to virtually no oil, typical of gas wells and coal bed methane wells. In addition to oil, there may be other liquids, called natural gas condensates, and water. Separation of liquids from gases is typically done at the wellhead. The resulting gas is referred to as raw natural gas.

According to State reporting data, there were 41,211 natural gas-producing wells of all types in New Mexico in 2006. These wells were owned by 506 firms, with ownership ranging from a single well to 6,083 wells. Total natural gas production in New Mexico for 2006 was 1,591,822.525 MMcf (million cubic feet).[2] About 64% of gas-producing wells are classified as gas wells, which includes coal bed methane wells.

Of the 18,913 producing oil wells in 2006, 78% (14,727) of them also produced natural gas. Oil wells contributed 231,365.774 MMcf, or 15% of total natural gas production in 2006. About 36% of gas-producing wells are classified as oil wells.

Production levels drive processing and transmission levels, and affect retail prices, which, in turn, affect levels of distribution.

2.1.1 Sources of greenhouse gases from the production segment

Methane emissions from the production segment account for 64% of the New Mexico natural gas industry totals, and come from gases either intentionally released during completion or during maintenance (vented), or from natural gas leaks (fugitive gas). Completion, the process of venting a new well to clear the shaft of drilling residues, water and waste gases, is a source of intentionally vented methane. According to the EPA/GRI report, the contribution to methane emissions during completions is negligible, particularly for infill wells (EPA/GRI – Venting). Infill wells – wells drilled into already-producing fields – are generally the rule in New Mexico. Carbon dioxide emissions by the production segment, accounting for 17% of the the New Mexico natural gas industry total, are due to fuel-burning. Total estimated 2006 segment emissions of methane are more than 9100 MMcf (CCAG-H7).

The principal sources of methane emissions from the production segment nationally are shown in Table 3. As the largest source of methane emissions in the segment, pneumatic devices will be the focus of greenhouse gas reduction in the production segment.

Table 3 – Principal sources of methane emissions by the production segment nationally.

Source	Pct of segment emissions
Pneumatic devices	37
Fugitive emissions	21
Dehydrators	17
Other	25

Source: (EPA/GRI – Executive Summary)

2.1.2 Economics of greenhouse gas reduction: the production segment

Specific emission reduction strategies that have been considered include refitting or replacing pneumatic devices, directed inspections and maintenance, and installing

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[2] 2006 well and production data from (OCD 2007)

plunger lift systems in gas wells (GasSTAR-T&P). The economic feasibility of any of these solutions for methane emission reductions depends on the current price of natural gas, the current costs of production of natural gas and the incremental costs that would be required in order to reduce emissions. In addition to being the major contributor to production segment methane emissions (see Table 3), refitting or replacing natural gas pneumatic systems it is a GasSTAR recommended Best Management Practice for this segment (GasSTAR-BMP) and it is also one of the least costly to remediate.

Pneumatic control systems at many wellheads are driven by natural gas at well pressure. In older devices, gas that is diverted into these systems is ultimately vented to the atmosphere. These are referred to as *high-bleed* devices. The refitting of devices, where appropriate, is estimated to cost $205 per device, while complete replacement is estimated to cost $682 per device, with a recurring annual cost of $30 (GasSTAR-Pneumatics)[3].

Assume that the conversion of high-bleed pneumatic devices to low-bleed would cost $682 (worst case) with a recurring annual cost of $30 and would eliminate an average of 192 Mcf of methane emissions per year per well (GasSTAR-Pneumatics). Amortized over ten years with a discount rate of 5%, that's a total annual cost of less than $141 per well per year. The 192 Mcf/year of recovered gas would increase revenue by a little more than $1186 per annum at the 2006 wellhead price. This represents a net increase in annual revenue of about $1046.

This outcome is consistent with case studies on the GasSTAR web page. The net positive revenue outcome begs the question: why haven't all wells been converted to low-bleed pneumatic systems? There are two possible explanations: 1) most wells with high-bleed pneumatic systems lose much less natural gas than the average, or 2) well operators employ exceptionally large discount rates. The first case may arise if most well operators believe that their own wells are better than the industry average. In the second case, a well operator is indifferent between avoiding an annual expense of $141 beginning this year and annual income of $1187 beginning next when the discount rate is slightly greater than 88%[4]. The petroleum industry is considered somewhat risky, with typical discount rates between 17.9% and 24.5% (Texas 2005). By employing a discount rate of 88%, however, well operators are revealing a level of uncertainty that is much greater than the overall economic uncertainties of the industry.

From a microeconomic or industry perspective, any increased production costs due to emission reductions will result in a shift in the supply curve, making natural gas relatively more expensive. Similarly, increased revenues, as in the example above, result in a supply shift that makes gas relatively less expensive. According to U.S. government figures for 2006, marketed natural gas produced in New Mexico was 1,609,223 MMcf

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[3] Remediation costs are taken from GasSTAR, either directly or through (CCAG-H7). Costs quoted in 2001 dollars have been inflation adjusted to 2006.
[4] The present value at discount rate of r of avoiding an expense of $141 annually in perpetuity starting this year is $\$141/r$. The present value of an income of $1187 annually in perpetuity starting next year is $\$1187(1/r - 1)$. Indifference means that the two present values are equivalent.

from 41,634 wells (EIA-NM)[5], while nationwide production was 19,381,895 MMcf (EIA-National), meaning that New Mexico provides 8.3% of the national supply. Costs imposed on New Mexico producers that are not imposed on producers in other states will result in New Mexico natural gas becoming relatively more costly to produce, which will make it relatively less competitive. Constituting a little more than 8% of the market, however, changes in New Mexico gas supply will have some effect on the national market.

The economic impact of requiring low-bleed conversions to New Mexico natural gas producers can be assessed by estimating the impact on the supply, which in turn impacts the equilibrium price and quantity of natural gas. If price increases and quantity demanded decreases, the number of productive wells will decrease. Similarly, if the price decreases and quantity demanded increases, the number of productive wells will increase.

Requiring low-bleed pneumatic devices on every New Mexico natural gas well may impact the supply of natural gas. The percent change in supply, ΔS, can be estimated by multiplying the price elasticity of supply, ε_s, by the percent change in costs, ΔC, where price elasticity of supply is defined as the percentage change in quantity supplied, given a 1% change in price. That is

$$\varepsilon_S = \frac{\partial Q_S}{\partial P} \frac{P}{Q_S},$$

where Q_S is the quantity supplied at price P. To first order, a cost increase can be treated like an equivalent reduction in price, so the percent change in supply then is

$$\Delta S = \varepsilon_S \Delta C.$$

The price elasticity of demand is the percentage change in quantity demanded given a 1% change in price, that is

$$\varepsilon_D = \frac{\partial Q_D}{\partial P} \frac{P}{Q_D},$$

where Q_D is the quantity demanded at price P. The change in price is determined by the change in supply multiplied by one over the sum of the elasticity of supply and the elasticity of demand. That is

$$\Delta P = \Delta S \left(\frac{1}{\varepsilon_S + \varepsilon_D} \right).$$

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[5] Note that the EIA numbers for New Mexico are not quite the same as the OCD numbers. According to Jane Prouty of OCD, these changes are due to differences in timing, pressure bases, and gas content. The EIA figures are used here to put New Mexico supply in context of total market supply.

Price elasticity measures for natural gas supply and demand are taken from (Wiser *et al* 2005) and (Bernstein and Griffen 2005), respectively. The absolute value of the price elasticity of demand is 0.1. Wiser (2005a) estimates an elasticity of supply of 0.83, but indicates a range of estimates of between 0.5 and 1.25 (Wiser 2005b).

Earlier in this section it was found that increased revenue exceeds cost by $1046 *per annum*. Treating this as a negative cost increase ($\Delta C = -0.5\%$) in factor cost for a break-even well with revenue of $238,867 (the New Mexico mean), the equivalent increase in supply and decrease in price can be calculated. Assuming the price inelastic nature of demand holds – a 0.1% increase in quantity demanded for every 1% decrease in price – the range of price and quantity changes given the three levels of supply elasticity are shown in Table 4.

Table 4 – Summary of price decrease and supply increase from captured pneumatic device emissions for a range of price elasticities of supply.

Elasticity of supply	Elasticity of demand	ΔP		ΔS		
		%	$ (2006)	%	Q (MMcf)	# wells*
0.50	0.1	–0.36%	–$0.02	0.22%	3,520	91
0.83	0.1	–0.39%	–$0.02	0.36%	5,870	152
1.25	0.1	–0.41%	–$0.03	0.55%	8,810	228

* based on average production per well in 2006

Requiring the incorporation of low-bleed pneumatic systems on new wells would not add significantly to new-well costs. As production from older wells falls, and as the oldest wells are shut in, the introduction of new wells so equipped could result in a steady decline of total emissions without retrofitting any existing wells. This will be explored in section 3.3.

A 20% reduction in segment emissions, constituting a 12.8% reduction in the New Mexico natural gas industry emissions, would be achieved with the conversion of less than 12,000 devices, or about 0.28 devices per well. Even if a significant number of wells have already converted to low-bleed systems, the conversion of 12,000 devices is still a feasible remediation. The total cost for 12,000 devices is about $1.69M, and the increased revenue ranges from $6.3M to $15,7M at the 2006 price, depending on price elasticity of supply, for a net benefit from $4.6M to $14.0M.

With a discount rate as high as 25%, this remediation is cost-effective for any wellhead price down to $4.57 per Mcf [4] or if recovered emissions are as low as 74% of the GasSTAR estimate of 194 Mcf per device per year.

A more in-depth analysis of the production segment is presented in section 3. The analysis there is by no means exhaustive, one of the major limitations being the paucity of data on actual wellhead production and emission volumes. Any remediation effort would have to address this as a first step. Thorough sensitivity analysis is only possible with detailed data on wellhead production and emissions.

2.2   Natural Gas Processing

The processing segment typically includes gathering, which involves transporting raw natural gas and any separated liquids from wellheads to processing facilities by midstream pipelines. The typical composition of raw natural gas is shown in Table 5. The processing segment separates the various hydrocarbon gases – primarily ethane, propane,

butane, and various pentanes – from other gases, such as water vapor, carbon dioxide, hydrogen sulfide, and atmospheric gases like nitrogen and helium[6]. The non-methane gases are compressed into liquids and distributed by truck. Similarly, some of the methane may also be compressed and sold as liquefied natural gas (LNG), which is distributed either by truck or by pipeline. Hydrocarbon gases occurring in non-economic quantities may be burned (flared). In New Mexico, non-hydrocarbon gases (water vapor, nitrogen, noble gases, and carbon dioxide) are typically vented to the atmosphere. In some other states, the carbon dioxide is compressed and piped to production areas to be injected into wells for enhanced recovery, but inexpensive carbon dioxide from the Bravo Dome CO_2 wells makes this non-economic[7]. Natural gas going into the processing segment is called *wet*, while natural gas after processing is called *dry*.

Table 5 – Composition of raw natural gas after separation of liquid petroleum (oil).

Typical Composition of Natural Gas		
Methane	CH_4	70-90%
Ethane	C_2H_6	0-20%
Propane	C_3H_8	
Butane	C_4H_{10}	
Carbon Dioxide	CO_2	0-8%
Oxygen	O_2	0-0.2%
Nitrogen	N_2	0-5%
Hydrogen sulfide	H_2S	0-5%
Rare gases	A, He, Ne, Xe	trace

Source: (NGSA-Composition)

There were 25 natural gas processing plants in New Mexico in 2004 (EIA-Processors). The New Mexico Environment Division lists 25 processing plants and three refineries in April 2007 (NMED-Plants).

2.2.1 Sources of greenhouse gases from the processing segment

Processing segment methane emissions account for 15.5% of the New Mexico natural gas industry total and arise from leaks and from venting for maintenance. Direct emissions of carbon dioxide from the processing segment account for 63% of the New Mexico natural gas industry total and arise from venting or burning waste gases and fuel-burning. The most significant contribution to greenhouse gasses is the venting of carbon dioxide in the processing of coal bed methane (46% of New Mexico natural gas industry CO_2 emissions). Total estimated 2006 segment emissions of methane are more than 2200 MMcf (CCAG-H7).

Approximately one-third of natural gas produced in New Mexico is coal bed methane (CCAG-CBM). Carbon dioxide constitutes as much as 18% of the gas from coal bed methane wells in New Mexico (CCAG-Processing). This gas, called *entrained* CO_2, is actually a property of the well, but is attributed to processing because that is where it is separated from the other gases. As mentioned above, this gas could be used for enhanced

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[6] This discussion of natural gas processing comes from (NGSA-Processing).
[7] Inferred from statements by the CCAG (CCAG-Processing).

recovery in some oil and gas wells. Additionally, waste carbon dioxide is sometimes stored (sequestered) in depleted wells to prevent its release into the atmosphere. Natural gas processing plants in New Mexico are subject to regulation and taxation. Processing plants tend to be geographically exclusive and therefore operate as monopolies or near-monopolies.

The principal sources of methane emissions nationally from the processing segment are shown in Table 6. Fugitive emissions, the largest source of emitted methane in the segment, may be reduced significantly with directed inspections and maintenance, as discussed in the next section.

Table 6 – Principal sources of methane emissions by the processing segment nationally.

Source	Pct of segment emissions
Fugitive emissions	67
Compressor exhaust	19
Other	14

Source: (EPA/GRI – Executive Summary)

2.2.2 Economics of greenhouse gas reduction: the processing segment

It is anticipated that 77% of processing plant fugitive emissions can be eliminated through directed inspections and maintenance (GasSTAR-DIM), which is a GasSTAR recommended Best Management Practice for this segment (GasSTAR-BMP). Based on the CCAG inventory, this amounts to a reduction of nearly 63 MMcf per year per plant, at an initial cost of a little more than $87,000 and a recurring annual cost of about $65,500 (CCAG-H7).

If processors are able to recover 77% of presently fugitive natural gas, the result would be a reduction of about 8% of the statewide total methane emissions. Putting the entire 63 MMcf recovered from emissions into the supply represents a supply increase of 0.0039%, which is unlikely to affect the market significantly.

There are two revenue streams for New Mexico processors: the value-added in drying natural gas and in the production of natural gas liquids (NGLs). The economic impact of emissions reduction for processors is complicated by several factors:

> **Gas content**. Processing takes raw natural gas, with relatively lower energy density due to contaminants and non-methane hydrocarbons, and produces dry natural gas with high energy density, as well as NGLs such as propane, butane, ethane and liquid natural gas (LNG). Coal bed methane, for example, has a high contaminant volume (mostly CO_2) and low NGL content. The costs of separating the components and disposing of wastes may be greater than the net revenue from NGL sales.

Oil prices. NGLs compete with oil distillates (and bio-fuels, to some extent) in a market subject to broad price fluctuations. Uncertainty in imported oil supply, for example, produces uncertainty in NGL profitability.

Natural gas prices. Ironically, because natural gas is a factor in their production, higher natural gas prices make NGLs less competitive with alternatives.

Contracts. Different types of contracts distribute the revenue and economic risks associated with NGL prices differently between the producer and the processor. This is discussed further in the next paragraph.

While in the long-run energy prices move in parallel, short-run movements between oil prices, NGL prices and natural gas prices can drastically alter the economics of natural gas processing. In terms of risks with regard to NGL prices, the extent to which processors are affected depends on the kinds of contracts they have with producers. There are three classes of processing contracts: fixed-fee (risk assumed by the producer), keep-whole (risk assumed by processor), and percent-of-proceeds (risk is shared), as well as hybrid combinations of these (Starr and Adair 1994).

While reduced emissions represent increased supply through improved technology, to whom that benefit falls also may be complicated by contractual arrangements. The following analysis assumes that both costs and benefits accrue to the processor, but different contracts may distribute either between the producer and the processor. Ultimately, although contracts may present different levels of stickiness, processors, being geographic monopolies, will maximize monopoly rents (profits) in the long run. Typically this means that cost increases are passed on to either producers or consumers.

Margins for natural gas processing have averaged $0.40 per Mcf historically, and have been trending toward $0.80 per Mcf (Baker & O'Brien 2006). If a directed inspections and maintenance (DI&M) program is begun in the first year and gas savings are seen in the second and subsequent years, the second year's savings amount to nearly $388,000 at the 2006 wellhead price[8].

Amortizing the initial cost over ten years with a 5% discount rate, there is an annual net gain from emissions reduction in processing of about $308,000 per plant at the 2006 wellhead price, or about $7.7M for all 25 plants. The annual net gain represents an increase in the margin of about half a cent, or 0.07%. Even if this saving is passed on in its entirety to either producers or consumers, it is unlikely to affect the market significantly. The total methane emission reduction is 1569 MMcf, or about 71% of the segment total.

With a discount rate as high as 25%, this remediation is cost-effective for any wellhead price down to $3.12 per Mcf or if recovered emissions are as low as 50% of the GasSTAR estimate of 63 MMcf per plant per year.

Natural gas processors operate in two disparate markets: the market for drying natural gas, and the market for natural gas liquids. Some may even participate in a third market for carbon dioxide. Because of the complexity of the processing segment and small number of plants in New Mexico, it is recommended that analysis be conducted on each

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[8] This assumes that gas is recovered before value-added processing.

of the 25 plants individually. Actual sensitivity to natural gas price fluctuations can only be determined with more data representative producer characteristics.

2.3   Natural Gas Transmission

Transmission in the natural gas industry means pipelines. Transmission pipelines take dry natural gas from processing plants either out of state or to in-state distribution points.

In addition to pipelines owned by midstream processors, there are five major pipeline operators in New Mexico: Transwestern Pipeline Company, El Paso Natural Gas Company, Public Service Company of New Mexico (PNM), Southern Trails Pipeline Company, and TransColorado Gas Transmission Company (EIA-Pipelines). There are 10375 miles of pipeline and 62 compressor stations in New Mexico (CCAG-H7). Transmission firms are considered common carriers (pursuant FERC Order 636, as well as subsequent orders) and may or may not be subject to market powers.

2.3.1   Sources of greenhouse gases from the transmission segment

Methane emissions from the transmission segment account for 15.5% of New Mexico natural gas industry totals, and are due to leaks and maintenance venting of compressors in addition to leaks in the pipes. Carbon dioxide emissions, accounting for 20% of the New Mexico natural gas industry total, are due to fuel-burning. Total estimated 2006 segment emissions of methane are almost 2118 MMcf.

The principal sources of methane emissions nationally from the transmission and storage segment are shown in Table 7. The EPA/GRI report does not distinguish between transmission and storage, and storage is not a consideration in New Mexico, so this study assumes that the overall averages apply to transmission alone. Fugitive emissions, the largest source of emitted methane in the segment, may be reduced significantly with directed inspections and maintenance (DI&M), a GasSTAR Best Management Practice recommendation for transmission (GasSTAR-BMP).

Table 7 – Principal sources of methane emissions by the transmission and storage segment nationally.

Source	Pct of segment emissions
Fugitive emissions	58
Blow and purge	16
Pneumatic devices	12
Compressor exhaust	10
Other	4

Source: (EPA/GRI – Executive Summary)

2.3.2   Economics of greenhouse gas reduction: the transmission segment

There are three general areas of reduction: stepped up inspection and maintenance, upgraded compressors, and modified cleaning and maintenance procedures (GasSTAR-

T&P). As with the processing segment, pipelines are subject to limited market pressure and are government regulated, so that government mandated expenses can be incorporated directly into costs without market distortion. El Paso Corporation has identified three process improvements as having "the highest viability for reducing emissions from the transmission industry": composite wraps for non-leak pipeline repairs, pumping down line pressure before maintenance, and using hot taps in service connections[9]. They conclude that "15 - 25% seems to be a reasonable reduction opportunity assuming the baseline is derived from the corresponding GRI factor."

A DI&M program for transmission compressor stations could reduce emissions by more than 29 MMcf per year per station at an initial cost of almost $30,000 per station and an ongoing cost of about $24,500 per station per year (CCAG-H7). For all 62 transmission compressor stations in New Mexico, this amounts to a reduction of a little more than 1800 MMcf per year, or about 86% of total segment emissions. Amortizing the initial cost over ten years, the total cost is more than $27,000 per compressor per year, for a total cost of almost $1.7M for all 62 compressors. The captured emissions represent a benefit of more than $12.4M at the 2006 city gate price of $6.82 (EIA-Price), for a net benefit of $10.7M, or $173k per compressor.

With a discount rate as high as 25%, this remediation is cost-effective for any city gate price down to $2.28 per Mcf or if recovered emissions are as low as 33% of the GasSTAR estimate of 29 MMcf per compressor per year.

As with the processing segment, because of the small number of pipeline firms, it is recommended that analysis be conducted at the firm level. Sensitivity to natural gas price fluctuations is only possible with a more detailed picture of representative firms.

2.4   Natural Gas Distribution

Distribution firms take natural gas from high volume, high pressure transmission pipelines to low pressure users. Many of these firms are municipalities. New Mexico being a net exporter of natural gas, distribution volume is a small fraction of production.

Distribution entities in New Mexico operate 8977 miles of main pipelines, 4944 miles of service pipelines, 340 metering stations, and 431 pressure regulation stations (CCAG-H7). In 2006, consumption by residential, commercial, and industrial users, including power stations, was 128,028 MMcf (EIA-Consumption), or 7.5% of total production. There were 552,701 New Mexico natural gas customers in 2004 (EIA-Consumption).

2.4.1   Sources of greenhouse gases from the distribution segment

Distribution pipelines are subject to leaks and maintenance venting, as well as leakage and waste by end users, contributing 5% of the New Mexico natural gas industry total. The segment is not a significant contributor to direct carbon dioxide emissions. Total estimated 2006 segment emissions of methane are almost 751 MMcf (CCAG-H7).

The principal sources of methane emissions nationally from the distribution segment are shown in Table 8. Underground leaks, the largest source of emitted methane in the segment, are distributed over 13,921 miles of distribution lines, under various

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[9] Naomi Cortez, Western PL Environmental Dept., El Paso Corporation. Email on 29 November 2007.

jurisdictions, making it a difficult remediation to assess. The second largest source of methane emissions are distribution meters and pressure regulating stations. DI&M programs at gate stations and surface facilities are a GasSTAR recommended Best Management Practice for this segment (GasSTAR-BMP), and will be discussed in the next section.

Table 8 – Principal sources of methane emissions by the distribution segment nationally.

Source	Pct of segment emissions
Underground pipeline leaks	54
Meter and pressure regulating stations	35
Customer meters	8
Other	3

Source: (EPA/GRI – Executive Summary)

2.4.2   Economics of greenhouse gas reduction: the distribution segment

Because distribution systems are either publicly operated, or are monopolies which are regulated for public benefit, it is appropriate that economic analysis of the distribution segment be done from the consumer point of view. New Mexico annual natural gas consumption is 128,028 MMcf (EIA-Consumption). The benefit of recovering all methane emissions amounts to $9.26 per customer per year at the 2006 city-gate price of $6.82 (EIA-Price). To break even, costs would have to be a maximum of $200 per mile for distribution lines, $2300 per station for surface facilities, and $0.75 per meter for customer meters. Distribution line inspection and monitoring is an expensive undertaking, especially for low-density municipalities. It is unlikely that customer meter inspection and replacement could be undertaken for less than a dollar per meter. At the level of this study, directed inspection and monitoring (DI&M) for meter and pressure regulating stations is the only clearly cost-effective remediation available to the distribution.

A DI&M program for distribution surface facilities could reduce emissions by 105 Mcf per year per station at an initial cost of $210 per station and an ongoing cost of $157 per station per year (CCAG-H7). For all 771 distribution metering and pressure regulation stations in New Mexico, this amounts to a reduction of nearly 81 MMcf annually, or about 11% of distribution emissions. Amortizing the initial cost over ten years, the total cost is $191 per station per year, for a total cost of less than $142,000 for all 771 stations. The captured emissions represent a benefit of $552,000 at the 2006 city gate price, for a net benefit of almost $405,000, or $0.73 per customer per year.

With a discount rate as high as 25%, this remediation is cost-effective for any city gate price down to $4.47 per Mcf or if recovered emissions are as low as 67% of the GasSTAR estimate of 105 Mcf per station per year.

Although further analysis of the distribution segment would be instructive, it is, at present, the least significant source of greenhouse gases, is highly heterogeneous, and impacts the economy in complex direct and indirect ways.

2.5   Economics of greenhouse gas reduction: summary

Table 9 summarizes the emission reduction remediations reviewed in the preceding sections. Inasmuch as the reductions total to nearly 42% of 2006 levels, the 20% goal is clearly attainable even without complete or across-the-board participation or compliance.

Table 9 – Summary of methane emission remediations reviewed in this section

Segment	Remediation	Reduction			Benefit (Cost)
		MMcf	% segment total	% industry total	
Production	pneumatic devices	2298	20	12.8	$4.6M to $14M
Processing	DI&M	1569	71	11.4	$7.7M
Transmission	DI&M	1800	86	17.2	$10.7M
Distribution	DI&M	81	11	0.55	$147k
Total		5748		41.95	$25M to $36M

The largest contributor to emissions is the production segment, which is evaluated in more detail in the following section.

3.0 Economic analysis of the production segment

Of the four general segments in the natural gas industry, production is the greatest contributor to methane emissions, and the only segment subject to nearly-full market pressures of competition. Thus, while there exist the greatest opportunities for methane emissions reductions, there are also the greatest economic risks. As discussed in section 2.1.2, increased costs can lead to reduced production which, in turn, leads to higher prices. Yet this very market power implies that firms are earning rents (additional profits) from their market power. The question, from an economic perspective, is how much additional cost can be absorbed by natural gas producers before the least productive are forced out of the market? From this can be inferred the economic impact of emission-reduction regulations and project the appropriate levels of government subsides, tax incentives, and fines for non-compliance. Additionally, the size and worth of markets for emission reduction credits or emission permits can be projected. These will inform any decision regarding the appropriate means for affecting emission reduction goals.

At the base of the discussion in the previous paragraph is the notion that representative cost functions[10] for New Mexico natural gas producers are known. There are likely to be multiple cost functions because different cost structures can result from differences in practices and differences in well characteristics, age, and gas properties. Cost structures can vary between firms, fields, and even wells within a field.[11]

The procedural and political complications of collecting the necessary data make it unlikely that disaggregated cost functions can be empirically estimated within the timeframe required. Even anecdotal evidence would be illustrative, but efforts in the course of this study to meet with producers were almost entirely unsuccessful. The three discussions that came out of the only meeting that occurred illustrated, more than anything else, a deep distrust of any regulatory effort or agency.

A second-best solution, then, is to construct a reasonable cost function for the New Mexico natural gas industry based on the best available information. The Energy Information Agency (EIA) collects gas well cost data that can aid in this endeavor. Unfortunately, the EIA data are provided by geographic region and New Mexico straddles two major EIA reporting regions – the San Juan and Raton Basins are incorporated into the Rocky Mountain Region, whereas the Permian Basin is included in the West Texas Region. For the purpose of this study, cost data from the West Texas Region is used to develop a cost model for the New Mexico natural gas industry. The development and analysis of the cost model is discussed in section 3.1. This model is used in section 0 with production and price forecasts through 2020. From these it will be possible in section 3.3 to examine emission reductions arising from the aging and attrition of older wells, increased emissions from new wells, and what overall level of emission reductions existing wells will have to achieve between now and 2020. Finally, section 0 will present various outcomes.

3.1 New Mexico natural gas production cost model

The only readily available per-well cost data (EIA-Cost) reports average well costs as a function of flow rate and well depth. Costs are modeled as a function of flow rate, production in Mcf per year, the depth of production (in feet), and year (to account for external economic impacts). That is

$$C\left(rate, depth\right) = \alpha \cdot rate^{\beta_{rate}} \cdot depth^{\beta_{depth}}$$

The cost function is estimated using the EIA data. Consistent with (Chermak and Patrick 1995), a Cobb-Douglas single-well cost model is developed[12]. The Cobb-Douglas specification allows for a multiplicative relationship of the independent variables, in this case, production and depth. This specification requires all independent variables be non-negative. This allows for differences in costs due to the depth of the well (deeper wells

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[10] A cost function gives the cost of production based on the amount produced.

[11] For more information concerning the disaggregation of costs see, for example, (Chermak and Patrick 1995).

[12] The Chermak Patrick model was based on individual well data and included more characteristics than are available from the EIA data, such as monthly flow rate, remaining reserves, and the age of the well

are more expensive) and higher flow rates may be more expensive (heavier equipment, more maintenance).

The form of the log-linear econometric regression is

$$\ln C\left(rate, depth\right) = \ln \alpha + \beta_{rate} \ln rate + \beta_{depth} \ln depth + \sum_{i=1}^{18} \delta_{i, year}$$

The multiplicative nature of the costs also introduces multiplicative heteroskedasticity (Greene 2002), exacerbated in this case because the flow rates and depths are averaged over only a few categories, as shown in Table 10. The data for this model (Tables H6 through H10) are for the West Texas Region, which includes New Mexico's Permian Basin wells.

Table 10 – Depth and flow rate data categories for which EIA data are available.

Table	Well Depth (1,000 ft)	Production Rate (Mcf per day)				
H6	2	50	250			
H7	4	50	250			
H8	8	50	250	500		
H9	12		250	500	1,000	
H10	16			500	1,000	5,000

The data were inflation adjusted to 2006 dollars using (BEA-Deflators). The results of a maximum-likelihood estimation which includes correction for multiplicative-heteroskedasticity are shown in Table 11.

Table 11 – Cost model regression results

Independent variable	Model Coefficient (Std. error)	Variance Coefficient (Std. error)
Constant	4.422661 (.0471053)*	-17.84486 (.128068)*
ln (rate)	.1197363 (.0031704)*	-2.891497 (.128068)*
ln (depth)	.5023441 (.0040557)*	5.469812 (.1714364)*
All year dummy variables *		

* significant to 1%

The model explains virtually all of the variation in the data and all parameters are significant[13]. Thus, the cost model is

$$C\left(rate, depth\right) = 83.3 rate^{0.120} depth^{0.502}$$

This model is applied to the New Mexico Oil Conservation Division all-wells database (OCD 2007). A scatter plot of estimated costs, eliminating zero cost estimates, is shown

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[13] Parameters are also fit for data-dependent variance terms. This is a product of the correction for multiplicative heteroskedasticity.

in Figure 5. To expose greater detail, Figure 6 eliminates average costs above the 2005 New Mexico average wellhead price of $7.51 (EIA-2005) as well as the highest quintile in production, which includes a few extremely productive wells. Ultimately, these data can be used to infer a supply curve, as shown in Figure 7.

3.2   Natural gas production forecast scenarios

Forecasting is easy: production will increase, decrease, or stay the same. Production from a natural gas well will decrease naturally over time until it becomes economically nonviable. As long as sources (reserves) exist, new wells will be brought into production. Whether these add up to increased, decreased, or unchanged total production depends on:

- The market price for natural gas
- The extent of natural gas reserves
- How quickly the new wells are brought into production (completions)
- The flow rates of the new wells

3.2.1   Natural gas price forecasts

The Consensus Forecast of natural gas prices by the New Mexico Legislative Finance Committee (LFC) are shown in Table 12 (Schardin and Francis, 2007, p. 6.), along with Congressional Budget Office inflation forecasts (CBO 2007). Between 2008 and 2012, effective (inflation adjusted) natural gas prices are expected to decrease. Historically, levels of production follow prices closely, so New Mexico natural gas production is expected to decrease over this time. The LFC forecasts a two percent annual decrease in natural gas production in New Mexico over this period. National natural gas wellhead prices are forecast to decline an additional 4.5% between 2012 and 2020 (EIA-Forecast). This supports a continued decline in natural gas production in New Mexico through 2020.

Table 12 –Legislative Finance Committee natural gas price projections for December 2007.

Year	Average NM wellhead price[1]	Forecast change[2]	Inflation[3]
FY08	$6.46	-1.67%	2.32%
FY09	$6.56	1.55%	2.23%
FY10	$6.59	0.46%	2.20%
FY11	$6.52	-1.06%	2.20%
FY12	$6.52	0.00%	2.20%

[1] Source (Schardin & Francis, 2007 – spreadsheet)
[2] Starting with FY07 actual of $6.57 (ibid)
[3] Congressional Budget Office CPI Forecast (CBO)

To forecast the effect of price change on the number of natural gas wells in New Mexico, it is necessary first to compute the gas-price elasticity of new-well starts. Historical data are available for active drilling rigs, which is a reasonable proxy given that 92% of the state's 43,248 active wells in 2006 produced natural gas. Monthly average rig counts from January 1990 through September 2007 (Baker Hughes) were ordinary least squares (OLS) regressed against lagged rig count and average New Mexico wellhead prices during the same period (EIA-Price).
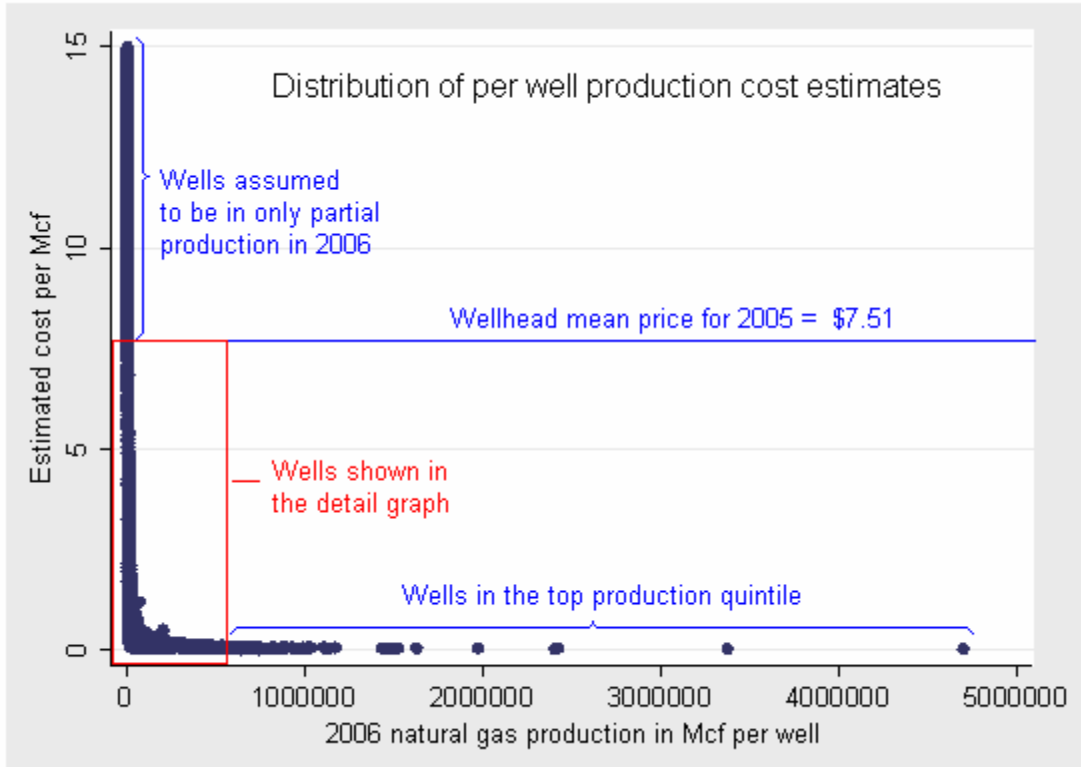
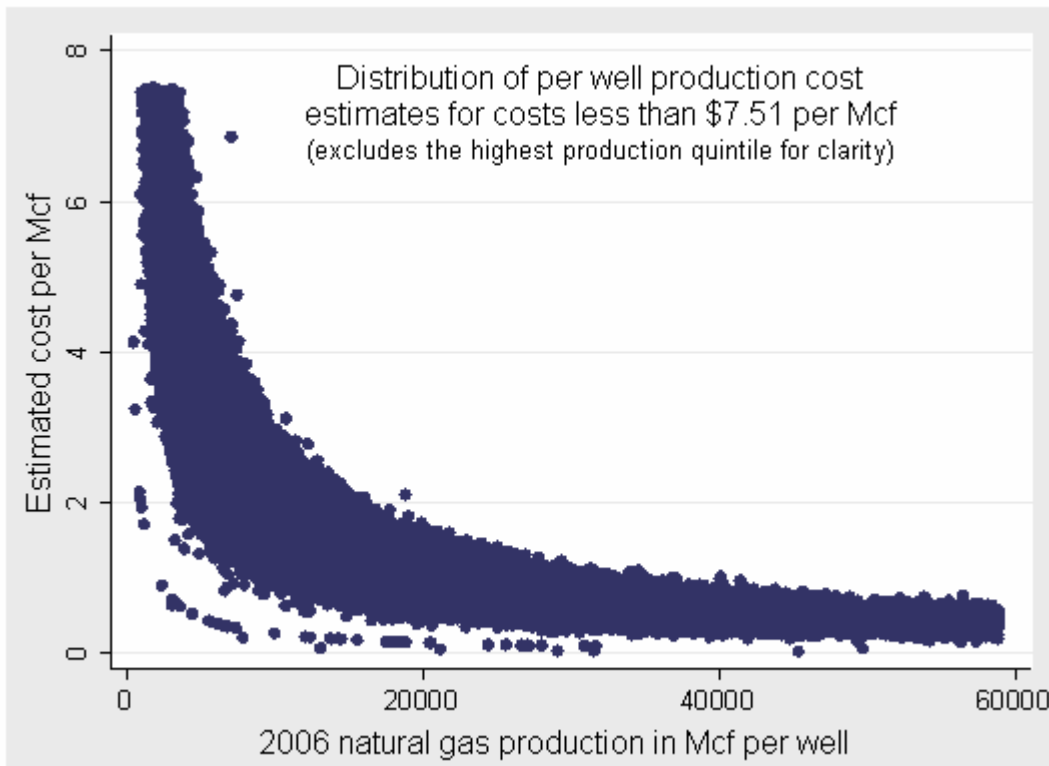**Figure 5 --Cost model applied to OCD data**
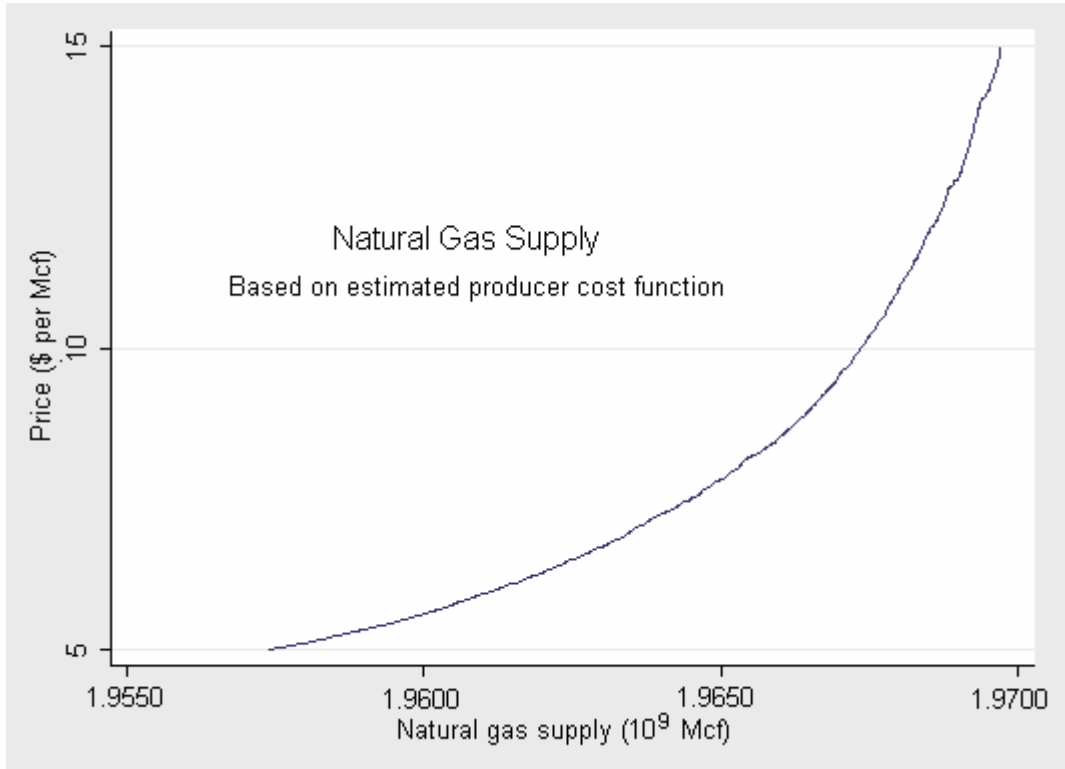

Figure 6 – Detail of cost model applied to OCD data

Figure 7 – Inferred supply function from cost estimate

That is, the AR(1) model

$$\ln rigcount_t = \ln \alpha + \beta \ln price_t + \gamma rigcount_{t-1}$$

Results are shown in Table 13. All coefficients are significant at the 1% level, and 89% of variations in the data are explained by the model. Note the near-unit value for the previous year variable. A Dickey-Fuller test confirms that this is a unit root and vector-error-correction regression reveals that rig count is essentially a random walk variable.

Table 13 – Regression results for price elasticity of rig count

Independent variable	Coefficient (Std. error)
Constant	.3638731 (.1009478)
ln (price)	.0639056 (.0183826)
previous year ln (rig count)	.8896625 (.1009478)

Given this outcome, there is no indication that changes in natural gas prices will affect the rate of well drilling, so that the number of new producing wells each year will likely remain fairly constant[14].

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[14] Decreasing production with a constant net increase in the number of wells can be explained in that most new wells are *in fill* wells – wells drilled into existing fields, essentially between existing wells. Production levels fall as the field is depleted, even as the number of wells depleting it increases.

3.3   Methane emission reductions through new well technology, old well attrition

The economics of designing and building new wells to emit less methane is somewhat more straightforward than the economics of retrofitting existing wells. When emission control costs are included in the initial cost proposal, wells that cannot be made emission-level compliant won't be drilled in the first place. With the addition of new, cleaner wells and the plugging of old, non-producing wells, the overall level of methane emissions may be reduced even before retrofitting existing wells.

Between 2001 and 2005 there was an average annual net increase in producing natural gas wells of 1242 (EIA-New) and an average of 258 gas wells were plugged annually during those years (OCD 2007), meaning that an average of 1500 new gas wells came into production annually during that time. The trend in natural gas wells is shown in Figure 8. In the historical EIA data, or OCD data before 2005, it's not possible to determine if an oil well also produced natural gas, so these figures include gas wells only. Overall, 36% of gas-producing wells in New Mexico are oil wells, so the actual trend in Figure 8 may be about 55% higher.
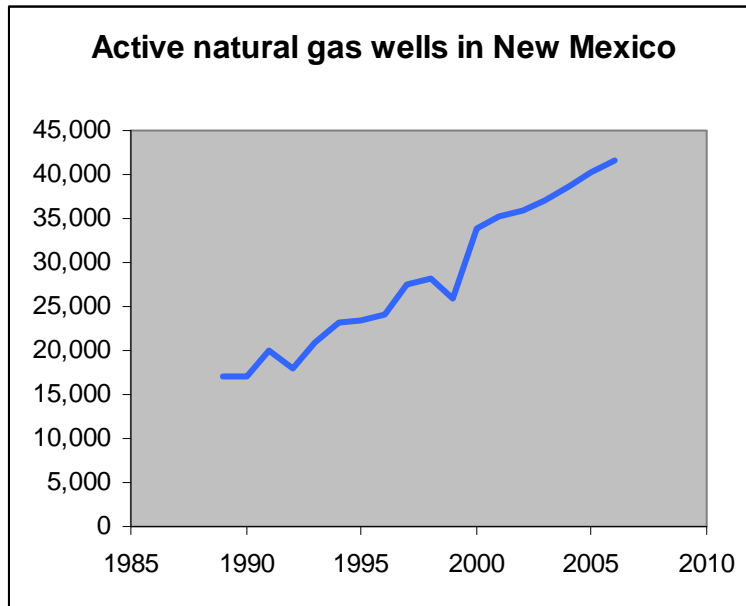
Active natural gas wells in New Mexico

**Figure 8 – Active natural gas wells in New Mexico,
1988 – 2006.** Source (EIA-New).

The average lifetime of all plugged gas wells in the OCD database is 18.7 years, and the average lifetime of all plugged oil wells is 14.7 years. The weighted average, assuming 36% of gas-producing wells are oil wells, is 17.2 years. Figure 9 shows the distribution of ages of gas-producing wells in 2006. Natural gas wells in the OCD database are retired at a mean rate of 0.737% per year.

Assume that older wells emit the 2006 average of 276 Mcf of methane per year and that all wells coming on line beginning 2008 emit at the lower average rate of 38 Mcf per

year[15]. The first three columns of Table 14 shows the retirement schedule for wells producing in 2006 based on this rate. Shutting in these wells eliminates an average of 276 Mcf per year of methane emissions or a total of 854 MMcf per year. During the same time, an average of 1500 new gas wells will be coming into production each year. Figure 8 shows the trend in the number of active wells over the past 20 years. If each of them emits 38 Mcf per year, the increase in emissions will be about 684 MMcf per year for the 18,000 added wells. These new wells are also subject to the mean retirement rate and are shown in the last two columns of Table 14. The shutting in of these wells eliminates an average of 82 Mcf per year of methane emissions for an additional reduction of 36 MMcf per year. The net impact is a reduction of 207 MMcf per year, or nearly 2.3% of 2006 segment emissions. This amounts to a reduction in total natural gas industry emissions of nearly 1.5%.
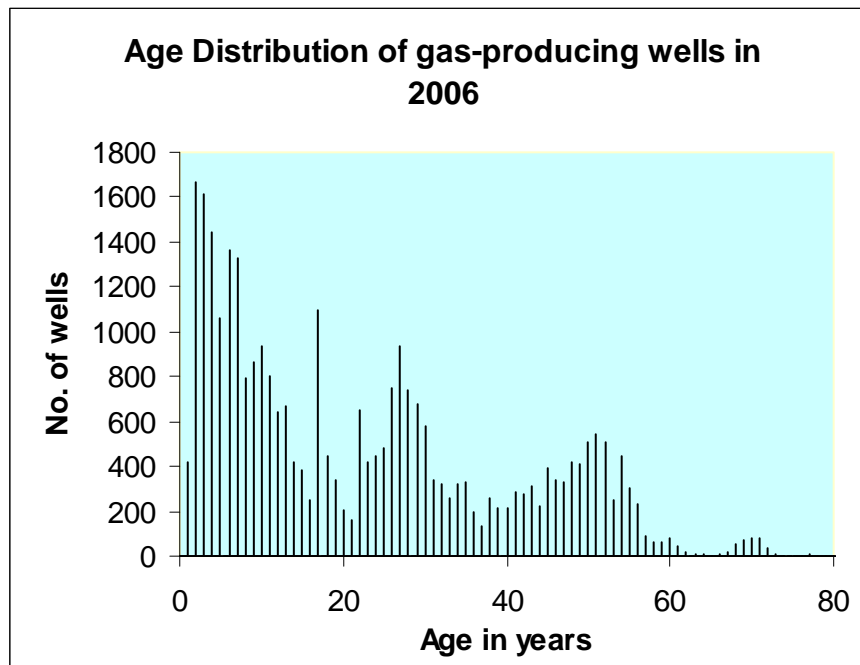

Figure 9 – Age distribution of gas-producing wells in 2006. Source (OCD 2007).

In addition to natural attrition due to age, there is an additional economic consideration with regard to the aging of wells. The economic viability of wells with added emission-reduction costs was discussed in section 2.1.2. Of interest is how that computation is affected by the aging of the well.

Figure 10 shows the estimated cost function developed in section 3.1 as a function of production level for five different well depths. At its simplest, the aging of a well is simply movement to the left along a line parallel to those shown. What is not evident from this graph is the point at which revenue falls below cost.

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[15] This is the equivalent eliminating 1.325 high-bleed control systems per well (CCAG-H7).

Table 14 – Emission reductions through attrition 2007 - 2020

Year	No. of pre-2008 wells shut in	Emission reduction through attrition (Mcf/year)	No. of post-2008 wells shut in	Emission reduction through attrition (Mcf/year)
2008	267	73,692	22	837
2009	263	72,588	33	1,251
2010	263	72,588	44	1,662
2011	263	72,588	54	2,070
2012	263	72,588	65	2,475
2013	263	72,588	76	2,876
2014	261	72,036	86	3,275
2015	259	71,484	97	3,671
2016	253	69,828	107	4,064
2017	248	68,448	117	4,454
2018	247	68,172	127	4,842
2019	245	67,620	138	5,226
Total	3,095	854,220	966	36,704

Source: (OCD 2007)
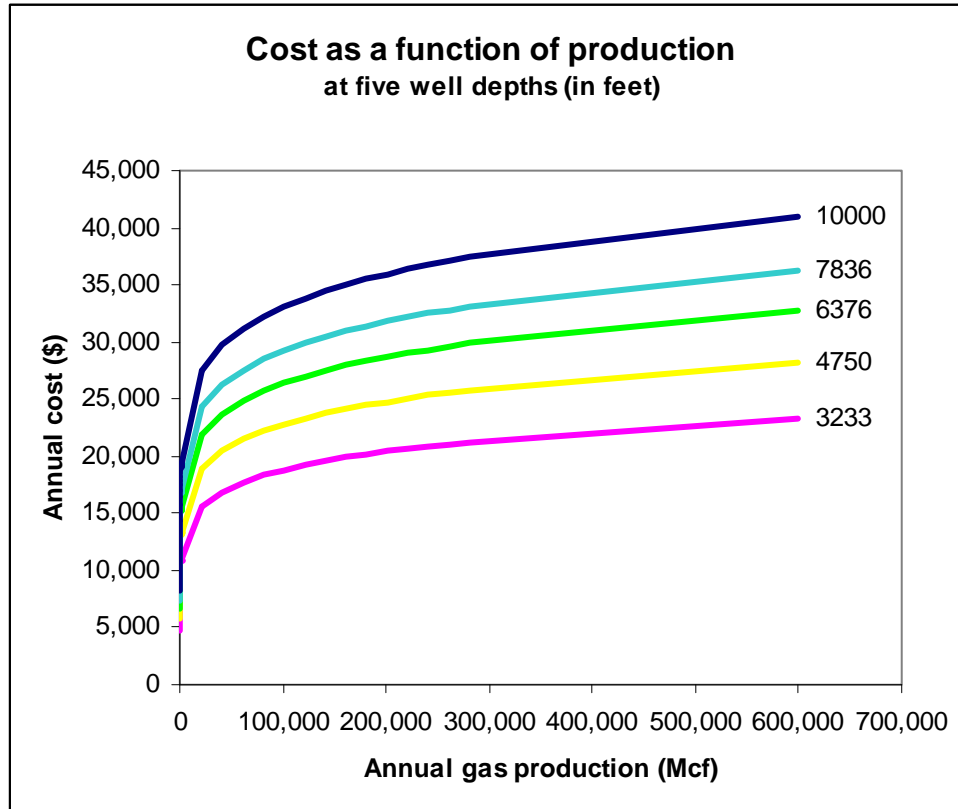
Figure 10 – The estimated cost function as a function of production level at five depths.

Table 15 and Table 16 show various cost statistics for wells grouped by cost quintile and by production level quintile. Table 15 includes a table of median well age per quintile,

and Table 16 includes difference between mean and median. Note here that the low production/high marginal cost group (upper right corner) has a mean of $6.89, well above the 2006 wellhead price of $6.18, but a median of about $6.00. This indicates that, although some wells in this group operate at a loss, more than half of them operate at break-even or better. The bottom table in Table 16 illustrates those groups that are skewed below the mean (pink cells) and those that are skewed above the mean (blue cells).

Over time, a given will move up the tables to lower production levels. As Figure 10 implies, marginal cost will not change significantly until the well is very close to end of life. The sparseness of the low production level/low marginal cost cells (lower left) in Table 16 implies that wells are shut in before they reach these levels.

Presumably new wells come into production in the lower rows of the table. Increased emission-reduction costs will move them further to the right, however. The quarter of a cent increases discussed in section 2.1.2 are not likely to move them by much – there's a roughly 50% increase in the mean marginal cost going across the table.

Thus, analysis of the cost model is consistent with the finding in section 2.1.2 and earlier in this section that increased emission-reduction costs will impact a few very-low-production very-high-marginal-cost wells, but otherwise the production segment can withstand the added costs of retrofitting or replacing high-bleed devices. With the strong correlation between high production rate (observable) and low marginal cost (non-observable), one regulatory approach may be to require low-bleed replacement for high-production wells for which, presumably, high revenues ensure its cost effectiveness.

3.4   Combined strategies for methane emission reductions

The decision on the best combined strategies to reach the 2020 goal will have to be based on a number of broad and possibly conflicting objectives. These objectives will have to consider:

1) impact on existing wells – any change in industry cost structures will have the greatest impact on older, low productivity wells. Policy-makers will have to weigh the economic costs of causing some wells to shut in a little earlier than planned against the benefits of reduced emissions, and possibly a reallocation of resources to newer, cleaner, more productive technologies.
2) impact on new wells – any program that shifts the advantage from older wells to new wells may have the consequence of over-stimulating new well development, consequently lowering the profitability of new wells.
3) impact on processors – policy-makers will have to consider carefully processors' contract portfolios, in particular the flexibility and duration of existing contracts, as well as existing regulatory burdens.
4) impact on pipelines – pipelines, like processors, will be subject to contractual and regulatory limitations.
5) impact on distributors – the distribution segment will be slow to change for myriad social and political reasons. Policy-makers will have to take an especially long view with regard to distribution entities.
6) impact to State tax revenues – the natural gas industry is a major source of revenue for the State of New Mexico. Many strategies, especially those involving

incentives, may be at odds with preserving the State's revenue stream. These things will have to be balanced carefully.

A follow-on study to this assessment could examine each of these strategies in detail.

4.0 Incentives, market solutions, and regulatory opportunities

The shortage of sound data is the biggest limitation to designing effective government incentives, market incentives, or regulatory measures. Without reasonable incentive and regulation packages, it is impossible to recommend among them. One recommendation to come out of this study is the urging to establish collection of consistent and timely data on methane production and emission levels as a function of well age, technology, region and type (gas versus oil). The reluctance of natural gas producers to provide information for this study may portend limited success for voluntary disclosure programs.

4.1   NMED identified emission reduction programs

Appendix F is a summary of implementation and enforcement methods prepared by Dominique Gomez, a Fellow in Public Policy with NMED in the summer of 2007. The following paragraphs address the economic impact of each of these measures.

4.1.1   Revolving loan fund

This isn't an incentive to compliance unless costs and benefits are very similar. The evidence that the natural gas industry has not already implemented apparently profit-enhancing programs suggests that costs and benefits are perceived as being quite far apart. For those firms that view costs and benefits as being very close, loans can shift the balance in favor of compliance. While many of the identified emission reduction opportunities (CCAG-H7) are fairly inexpensive, some (replacing gas-fueled compressors with electric, for example) tie up significant amounts of capital. A revolving loan fund (RLF) lowers the opportunity cost of tying up that capital. An incentive would either reduce the total opportunity cost of compliance below other capital alternatives (by providing a tax break, for example), or raise the opportunity cost of the alternatives (by imposing a fine, for example). There is a regulatory aspect to loans for emission reduction: ensuring that the funds are used as intended, and that their use actually achieves lower levels of emissions. This is not a good solution for measures incurring large ongoing (operations and maintenance) costs.

4.1.2   Subsidies for new technology

Again, this is not an incentive to compliance but rather a means to comply. See the discussion in section 4.1.1. For a subsidy, the opportunity cost of compliance is even lower than with a loan (assuming the subsidy is a grant and not a loan), but it doesn't provide a means for making compliance the lowest opportunity cost alternative. Additionally, as with loans, there is limited relief for large ongoing costs, and there will be significant enforcement costs.

Table 15 – Marginal cost statistics and well age by production and cost quintiles

		Number of wells				
		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**	0	6	3	761	5683
	2	10	21	982	4670	770
	3	32	995	4404	1022	0
	4	871	4519	1063	0	0
	5	5540	912	1	0	0
		Mean marginal cost				
		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**	.	0.63145	1.198442	2.577402	6.890304
	2	0.274526	0.682274	1.182961	2.091777	3.544154
	3	0.268195	0.625512	1.061744	1.605991	
	4	0.321454	0.574483	0.863363		
	5	0.213177	0.455666	1.173159		
		Marginal cost std. dev.				
		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**		0.065464	0.268375	0.334415	3.075839
	2	0.107603	0.085221	0.161426	0.423944	0.430833
	3	0.123974	0.091811	0.173461	0.169843	
	4	0.058091	0.098101	0.094335		
	5	0.107385	0.049914			
		Ratio std. dev. to mean				
		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**		0.103672	0.223937	0.129749	0.446401
	2	0.391961	0.124907	0.136459	0.202672	0.121562
	3	0.462252	0.146777	0.163374	0.105756	
	4	0.180713	0.170764	0.109264		
	5	0.503734	0.109541			
		Mean well age in years				
		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**		2.90	17.50	27.60	25.17
	2	1.83	12.84	24.82	25.35	18.85
	3	9.60	21.77	25.62	20.31	
	4	17.85	24.23	21.25		
	5	13.06	15.24	1.24		

Table 16 – Marginal cost extrema, median, and skew

		Minimum marginal cost				
		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**	.	0.515909	0.890981	1.495813	3.054356
	2	0.059372	0.42085	0.764759	1.410666	3.053874
	3	0.038895	0.401952	0.761267	1.411131	.
	4	0.019885	0.400949	0.761339	.	.
	5	0.005615	0.399985	1.173159	.	.

		Maximum marginal cost				
		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**	.	0.711778	1.385729	3.04875	15.00135
	2	0.391698	0.75794	1.410557	3.053679	6.855237
	3	0.399025	0.760929	1.410565	2.3977	.
	4	0.399911	0.761239	1.297859	.	.
	5	0.399945	0.656666	1.173159	.	.

		Median marginal cost				
		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**	.	0.639648	1.318617	2.641198	5.999467
	2	0.288821	0.711526	1.209508	2.040999	3.432908
	3	0.342215	0.642553	1.046113	1.556177	.
	4	0.330101	0.568829	0.832329	.	.
	5	0.211513	0.442756	1.173159	.	.

		Median minus mean				
		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**		0.008198	0.120175	0.063796	-0.89084
	2	0.014296	0.029252	0.026547	-0.05078	-0.11125
	3	0.07402	0.017041	-0.01563	-0.04981	
	4	0.008648	-0.00565	-0.03103		
	5	-0.00166	-0.01291	0		

4.1.3   Carbon tax

A carbon tax may provide the shift necessary to make compliance the lower opportunity cost alternative. However, taxation is a two-edged sword: the temptation is to replace some of the existing taxes on natural gas with an equal carbon tax to lessen the impact of taxation, but long-run reduced emissions lowers the State's tax revenue. Thus, the State has a clear incentive to increase tax rates in the long run, which makes firms apprehensive in the first place.

A related approach is pollution tax credits where reductions in emissions are rewarded with tax credits. If implemented as a one-time credit, it works like loans or subsidies, whereas an ongoing credit works like a negative tax. Ultimately, the public policy purpose of taxation is to transform the external costs (global climate change) into internal

costs. While an uncompensated carbon tax accomplishes this, tax credits effectively transfer the external cost to the taxpayers rather than to the generators of the externality.

4.1.4 Cap and trade policies

The cap-and-trade approach to emission control sets an allowance to be distributed among emitters, then allows those who under-emit to trade with those who over-emit.

To implement a cap-and-trade program, the State must:

- Set emission limits (caps) – with all the monitoring and enforcement infrastructure that entails (see section 4.1.7)
- Guarantee property rights for allowances

The rest of the program and its success lie with the marketplace. There is no guarantee that a market will form, or that it will work efficiently. Some natural gas producers in New Mexico have expressed skepticism about a CTA program based on a belief that the State could, and would, capriciously eliminate property rights for allowances.

4.1.5 Transparency requirements

Transparency may work as an incentive in consumer markets, but has little effect in a commodity market where the producers are effectively anonymous

4.1.6 Tax Incentive for Participation in EPA's Gas STAR

Tax credits as incentives are covered in section 4.1.3.

4.1.7 Legislation requiring reduction

As mentioned in section 4.1.4, voluntary programs only work if the State has some teeth behind them. For any program to work, the State will have to set appropriate levels, establish a monitoring program, develop monitoring expertise to enforce both monitoring requirements and compliance levels, and have the ability to punish infractions with enough speed and force as to provide a disincentive for cheating. Federal cap-and-trade programs have been successful in part because all of the infrastructure, best practices, enforcement mechanisms, and enforcement agencies were mature when the programs were introduced (Tietenberg *et al* 1999). In New Mexico, this will take considerable action by both the legislature and the executive. In effect, any program will have to begin with legislation.

5.0 <u>Summary</u>

This assessment shows that at least 20% reduction in methane emissions is economically feasible in the production, processing and transmission segments. A 20% reduction in emissions by the distribution segment are probably feasible, but would require significant coordination with the myriad distribution systems, many of which are publicly owned. 20% of distribution emissions, however, amount to 1.2% of the other segments emissions, so an overall 20% reduction is feasible without the distribution segment.

There are two general results of this analysis.

The first result is that the production segment, being subject to market pressures, cannot escape some transformation as a result of emission-reduction policies. The most likely outcome is the early shutting in of a few hundred near end of life wells. The rest of the

production segment can easily bear emission-reduction costs. The production segment is most likely to respond to market-based programs like cap-and-trade after the fallout from initial implementation.

The second result is that the processing, transmission, and distribution segments, being in near-monopoly markets, are able to pass on added emission-reduction costs. These segments also require capital-intensive remediations, making them most likely to take advantage of loans, subsidies, or other fixed-cost offsetting programs.

Acknowledgements

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