BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF THE PETITION TO ADOPT NEW REGULATIONS WITHIN 20.2 NMAC, STATEWIDE AIR QUALITY REGULATIONS, TO REQUIRE GREENHOUSE GAS EMISSIONS REDUCTIONS NEW ENERGY ECONOMY, INC. PETITIONER	)))))))	EIB No. 8-19 (R)

REBUTTAL TESTIMONY OF ELIZABETH PARANHOS

My name is Elizabeth Paranhos and I will be rebutting the testimony of Bruce A. Gantner and Darren Smith regarding the availability of technologies to reduce methane and carbon dioxide. My education and experience are described in attached NEE Rebuttal Exhibit R24.

A. INDUSTRY WITNESSES SMITH AND GANTNER TESTIFIED THAT THERE ARE NO TECHNOLOGIES OR PRACTICES AVAILABLE TO REDUCE METHANE FROM OIL AND GAS PRODUCTION, PROCESSING OR TREATING ACTIVITIES.[1]

Companies in the Oil and Natural Gas industry, in conjunction with the United States Environmental Protection Agency, have developed and implemented over one hundred technologies and practices to reduce fugitive and vented methane from oil and gas sources in the exploration, production, processing, storage, transmission and distribution sectors. To date, oil and gas companies have saved over $800 million through the implementation of such practices and technologies.[2] According to EPA, broad adoption of methane reduction measures has the potential to reduce 2008 estimated methane emissions from oil and gas activities by approximately 41 Mmt CO_2e.[3] A recent study estimated methane losses during well completions, production, processing and transmission in the Barnett Shale alone were 13.1

[1] Gantner at 7-20; Smith at 10-15.
[2] U.S. EPA, Natural Gas STAR Program, available at http://www.epa.gov/gasstar/.
[3] U.S. EPA, Natural Gas STAR Program, available at http://www.epa.gov/gasstar/. Based on a thirty percent reduction from 2008 emission levels.

bcf/yr, or about 1 percent of total gas production. At $3.50/mcf, this amounts to $46 million per year in lost revenues for producers.[4] While companies must make an initial upfront investment to install methane capture or reduction technologies, the return on investment in many cases is quite short—sometimes months—and almost always within a single year. In 2008, companies that employed methane reduction technologies reported savings of more than $802 million in additional natural gas sales.[5]

The following is a list of some of the most cost-effective technologies or practices that are available today. Some of these technologies or practices could be used to produce the requisite GHG reductions required by the proposed rule, while others could provide valuable offsets. A number of these technologies are currently required in Colorado and Wyoming. While implemented in these states as part of policies aimed at reducing emissions of air toxics and volatile organic compounds, these technologies are equally effective at reducing methane.

1. **Use of Low or No-bleed Pneumatic Devices**.

Pneumatic devices are used throughout the production, processing and transmission of natural gas, and the production of crude oil, to automatically operate valves and control pressure, gas flow, temperature or liquid levels.[6] As the following chart illustrates, pneumatic devices account for the largest percentage of natural gas production fugitive emissions—nearly 4 times as much as the other leading causes of emissions: dehydrators and pumps.

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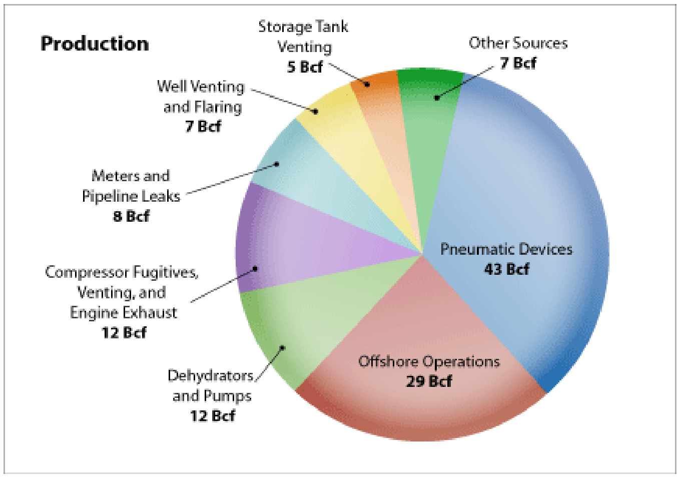
[4] Al Armendariz, Ph.D., *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements*, 6 (Jan. 26, 2009), NEE Ex. R25.

[5] EPA Natural Gas STAR, Accomplishments, available at http://www.epa.gov/gasstar/accomplishments/index.html, last visited December 14, 2009.

[6] *See* U.S. EPA, Lessons Learned from Natural Gas STAR Partners, "Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry", *available* at http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf, NEE Ex. R26.

Figure 4: Oil and Natural Gas Production Sources of Methane Emissions



Source: EPA, http://www.epa.gov/gasstar/basic-information/index.html

Pneumatic devices are designed to vent natural gas. However, some bleed or vent at rates significantly lower than others yet still achieve the same overall performance. Replacing high with low or no-bleed pneumatic devices results in significant gas savings and has a payback period of less than one year.[7] This practice has saved natural gas operators $61.2 million and as much as 20.4 bcf of methane gas to date.[8]

Colorado requires that all new, replaced or repaired pneumatic devices at production facilities must be low or no-bleed.[9] In addition, all pneumatic controllers at exploration and production sites, upstream natural gas compressor stations, natural gas drip stations and gas processing plants located in an ozone nonattainment or attainment/maintenance areas must have VOC emissions equal to or less than a low-bleed controller.[10] All new pneumatic controllers and

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[7] *Id.* EPA defines a high-bleed device as one that releases natural gas in excess of 50 Mcf a year.
[8] *Id.*
[9] CO Regulation 7, XVIII, entire Regulation 7 attached as NEE Ex. R27; Colorado Oil and Gas Conservation Commission Rule 805(b)(2)(E), entire Rule 801 attached as NEE Ex. R28.
[10] CO Regulation 7, XVIII.C. Upstream means upstream of natural gas processing plants.

existing pneumatic controllers located at a modified facility in the state of Wyoming must be low or no-bleed or route discharge streams to a closed loop system.[11]

1. Well Completions

Well completion activities are another significant source of methane. One cost-effective way to significantly decrease well emissions is to use portable or permanent equipment to recover, rather than release through venting or flaring, natural gas during the final well drilling process ("Green completions"). EPA estimates $176 million (25.2 Bcf) of natural gas can be recovered annually using green completions.[12] In the Barnett Shale Devon Energy reported that between 1990 and 2009, it prevented the release of approximately 35.47 Bcf of methane through the use of "reduced emissions completions", generating an additional approximately $106,596,000 million in revenue from increased sales of natural gas.[13]

Colorado currently requires the use of green completions on all oil and gas production wells unless not technically and economically feasible.[14] Wyoming has required the use of green completions in the Jonah-Pinedale Anticline Development Area ("JPAD") since 2007 and has recently expanded this requirement to all areas of concentrated oil and gas development (concentrated development areas or "CDA"s) in the state.[15] Montana requires that VOC vapors greater than 500 British thermal units per cubic foot from wellhead equipment with the potential to emit 15 tpy or greater be routed to a capture or control device such as a pipeline or flare.[16]

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[11] Wyoming Oil and Gas Production Facilities, Chapter 6, Section 2 Permitting Guidance (March 2010) ("WY Revised March 2010 Guidance"), at 10, 17, 21, entire guidance attached NEE Ex. R29.

[12] U.S. EPA,"Opportunities for Methane Emissions Reductions from Natural Gas Production." Producer's Technology Transfer Workshop, 8 June 2006, available at http://www.epa.gov/gasstar/documents/workshops/midland-2006/gremillion.pdf, NEE Ex. R30.

[13] Devon's Natural Gas STAR Experience, slide 20 NEE Ex. R31.

[14] Final Rule, Colorado Oil and Gas Conservation Commission, § 805(b).

[15] WY Revised March 2010 Guidance, *supra* note 11, at 15.

[16] MT Admin. Rules § 17.8.1711. This rule applies to all oil and gas facilities that have the potential to emit 25 tpy of a regulated air pollutant, including HAPs. Oil and gas facilities include wells and associated equipment used to produce, treat, separate or store oil, natural gas, or other liquids produced by the well. MT Ann. Code (2009) § 17

2. Glycol Dehydrators

Glycol dehydrators are widely used in the production, processing and transmission of natural gas. EPA estimates that glycol dehydrators emit approximately 1 Bcf of methane to the atmosphere annually. A number of technologies are available to reduce emissions from glycol dehydrators including installing flash tank separators, reducing the glycol circulation rate and using electric pumps instead of gas-assisted pumps.[17]

In Colorado, oil and gas operators must control actual, uncontrolled VOC emissions of 15 tpy or more from vents on glycol dehydrators (individual units or the aggregate emissions from all dehydrators at a site) located at all oil and gas exploration and production operations, natural gas compressor stations, drip stations or gas processing plants by 90%.[18] More stringent requirements apply to glycol dehydrators located within a one-quarter mile of a public place in Garfield, Mesa and Rio Blanco counties in the Piceance basin. Operators in these areas must control emissions of VOCs by 90% from all dehydrators with a potential to emit 5 tpy of VOCs.[19]

Wyoming requires control of HAPs and VOCs by at least 98% at all new and existing dehydration units operating in the JPAD regardless of total actual or potential emissions.[20] All new and existing dehydrators in CDAs and statewide must control HAPs and VOCs by 98%

2-1701. Subchapter 17 attached as NEE Ex. R32.

[17] U.S. EPA, Lessons Learned from Natural Gas STAR Partners, "Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators", 1, *available* at http://www.epa.gov/gasstar/documents/ll_flashtanks3.pdf, NEE Ex. R33.

[18] CO Regulation 7, XII.H.

[19] Final Rule, Colorado Oil and Gas Conservation Commission, § 805(b).

[20] WY Revised March 2010 Guidance, *supra* note 11, at 37.

upon the first date of production ("FDOP"). Controls may be removed after one year if emissions ≤ 6 tpy and units are equipped with still vent condensers.[21]

3. Crude Oil, Condensate and Produced Water Tanks

Field crude oil, condensate and produced water storage tanks used in the production, storage and transmission of natural gas and in oil production are another significant source of methane. Flash emissions occur during the transfer of liquids from separation equipment to atmospheric storage tanks. Breathing or standing losses occur when vapors are evaporated or displaced from tanks due to rising liquid level and changes in temperature.[22] Installation of vapor recovery units can capture approximately 95% of methane vapors (as well as other air pollutants) from storage tanks, save operators up to $260,060 per year, and has a payback of three months.[23]

Flares are an alternative method for reducing methane emissions from condensate, crude oil and produced water tanks. Flares are capable of a 98% destruction efficiency. A study done by URS Corporation in Texas concluded that "flares were able to cost effectively reduce VOC emissions at $40/ton".[24]

Wyoming requires that VOC emissions from condensate, oil and produced water tanks located at new or modified facilities in the Jonah-Pinedale Anticline Development Area and concentrated areas of development must control flash emissions upon the first date of production regardless of the amount of emissions. These facilities may remove controls after one year if emissions are < 8 tpy of VOCs. Statewide, new and modified facilities must control VOC flash

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[21] Alternatively, upon FDOP units must be equipped with reboiler still vent condensers and glycol flash separators. If , after 30 days, potential VOCs ≥ 8 tpy, units must install combustion control capable of reducing emissions by 98%. After one year, combustion units may be removed if total potential VOC emissions ≤ 8 tpy. *Id*. at13.

[22] U.S. EPA, Lessons Learned from Natural Gas STAR Partners, "Installing Vapor Recovery Units on Crude Oil Storage Tanks" 1, *available* at http://www.epa.gov/gasstar/documents/ll_final_vap.pdf, NEE Ex. R34.

[23] *Id*.

[24] Armendariz, *supra* note at 4 at 33.

emissions ≥10 tpy by 98% upon FDOP and may remove controls after one year if emissions are < 8 tpy.[25]

Colorado currently requires the control by 95% of VOC emissions from condensate, crude oil and produced water tanks with a potential to emit 5 tpy of VOCs that are located within a one-quarter mile of a public place in Garfield, Mesa and Rio Blanco counties in the Piceance basin.[26] Owners or operators of condensate tanks whose cumulative actual uncontrolled VOC emissions are ≥ 30 tpy located at exploration and production sites within ozone nonattainment areas and nonattainment/maintenance areas must meet declining emissions reductions over time. For example, such operators must reduce overall VOC emissions from all of their tanks emissions by 81% during the 2009 ozone season (May 1- Sept. 30) and by 85% in 2010 (such owners/operators do not need to apply controls to every individual tank). Owners or operators must reduce non-ozone season emissions by 70% in 2009 and 2010. Controls used to produce the requisite reductions must achieve a a 95% control efficiency.[27] Additionally, tanks installed after February 1, 2009 that are controlled with a combustion device must be equipped with an auto-igniter upon startup. Statewide, new and existing condensate tanks that emit ≥ 20 tpy of VOCs must control emissions by 95%.[28]

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[25] Note that the emission threshold for the application of this requirement differs depending on an individual tank's location. For example, all tanks located in the Pinedale-Anticline Development Area must control emissions upon production, regardless of the amount of emissions. Tanks located in Concentrated Development Areas with potential and actual emissions of 8 tpy must comply with specified emissions limitations whereas other tanks located statewide need only install control technologies if potential emissions equal 10 tpy or more and actual emissions equal or exceed 8 tpy. WY Revised March 2010 Guidance, *supra* note 15 at 18, 11, 5.

[26] Final Rule, Colorado Oil and Gas Conservation Commission, § 805(b).

[27] CO Regulation 7, XII.D.1. *See also* Colorado DPH&E Air Pollution Control Division, Oil and Gas Exploration & Production Regulation No. 7 Requirements, http://www.cdphe.state.co.us/ap/sbap/SBAPoilgastankguidance.pdf.

[28] CO Regulation 7, XVII.C.1.

Montana requires that VOC vapors greater than 500 British thermal units per cubic foot from wellhead equipment and oil and condensate storage tanks with the potential to emit $\geq$ 15 tpy be routed to a capture or control device such as a pipeline or flare.[29]

> A TCEQ case study illustrates the cost savings that can be realized from pollution control technologies, in this instance a storage tank battery in North Texas releasing 190 mcf/day of gas, with a heat content of 2400 Btu – 2.4 times higher than standard natural gas. Capturing the gas could have a monthly value of $68,000 (assuming $5/mcf natural gas price adjusted for the higher heat content of the captured vent gas). In this case, the simple payback period for a vapor recovery unit costing $32,000 would be 14 days ($32,000/$68,000 per month = 14 days). Some vendors of vapor recovery technology also offer alternative financing options to the outright purchase of the equipment, including providing the equipment at no up-front cost in return for a share of the recovered product.

4. Production Fugitive Emissions

There are a large number of uncontrolled fugitive sources in the production sector. California's Climate Change Scoping Plan proposes to address fugitive emissions from the extraction process of the state's large oil and gas industry, including on and off-shore sources. These emissions are from well and process equipment venting: leaks of flanges, valves and other fittings on the wells and equipment; and from separation and storage units such as sumps and storage tanks. Controls for the fugitive sources range from applying simple fixes to existing technologies to deploying new technologies to replace inefficient equipment and detect leaks and would include: improving operating practices to reduce emissions when compressors are taken off-line; installing compressor rod packing systems; substituting high bleed with low bleed pneumatic devices; improving leak detection; installing electronic flare ignition devices;

[29] MT Admin. Rules § 17.8.1711.

replacing older equipment (flanges, valves, and fittings); and installing vapor recovery devices. These are proven technologies according to the U.S. EPA's Natural Gas STAR program, which will pay back investments in a short period of time through saleable natural gas savings. California's proposal is expected to reduce fugitive methane emissions by approximately 0.2 MMTCO2e per year, beginning in 2015 and result in net annualized savings of $3.7 million.[30]

5. Plunger Lifts and "Smart" Well Automation during Well Unloading

Operators often remove unwanted fluids from mature gas wells through "well unloading"- practices that lead to venting of methane. One way to remove unwanted fluids without venting while also improving well productivity is to install a plunger lift system and "smart" well automation system. Plunger lifts use gas pressure buildup in the well casing-tubing annulus to operate a steel plunger that pushes liquids to the surface.[31] Smart well automation maximizes the efficiency of plunger lifts by routinely varying plunger well cycles to match key reservoir performance indices. Natural Gas STAR partners have reported annual gas savings averaging 600 thousand cubic feet (Mcf) per well and increased gas production of up to 18,250 Mcf per well, worth an estimated $127,750 through the implementation of plunger lifts. Installing smart well automation on plunger lift systems typically results in an average savings of 500,000 cubic feet of methane per well, per year.[32]

6. Installation of BASO Valves on All Gas-fired Heaters

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[30] *See* California's Climate Change Scoping Plan, available at http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf, ES-5, 3, 54-56, and V. 1 of Appendices, http://www.arb.ca.gov/cc/scopingplan/document/appendices_volume1.pdf, C153, selected pps attached as NEE Ex. R35.

[31] U.S. EPA, Lessons Learned from Natural Gas STAR Partners, "Installing Plunger Lift Systems in Gas Wells", *available* at http://www.epa.gov/gasstar/documents/ll_plungerlift.pdf, NEE Ex. R36.

[32] U.S. EPA, "Opportunities for Methane Reductions from Natural Gas Production", *available* at http://www.epa.gov/gasstar/documents/gremillion.pdf, *supra* note 12.

Crude oil heater-treaters, gas dehydrators and gas heaters located at exploration and development sites have pilot flames which can be extinguished by strong winds, causing the venting of natural gas. BASO valves automatically shut off the flow of natural gas upon the extinguishment of the pilot flame, thereby preventing unnecessary pollutant and methane losses. BASO valves are operated by a thermocouple that senses the pilot flame temperature and do not require electricity or manual operation. They are therefore ideal for remote locations. Capital costs are negligible, with each valve costing less than $100, and savings can be as great as 203 Mcf year for a 1,000 barrel per day heater-treater that experiences a flameout period of 10 days annually. Payback depends on how often the pilot flames go out and for what length of time. Typically payback occurs in less than 1 year.[33]

7. Leak Detection and Repair at Compressor Stations in the Transmission and Storage Sectors.

Compressor stations occur throughout the natural gas transmission and storage sectors and act to compress the gas to varying pressure points to overcome pressure losses that occur along a long-distance pipeline. According to EPA, compressor stations in the transmission sector alone account for approximately 50.7 bcf of methane emissions annually.[34] A leak detection and repair program, similar to that already required for equipment and compressors located at natural gas processing plants, *see* 40 C.F.R. Part 60, Subpart kkk, offers a cost-effective way to prevent and eliminate emissions from compressor stations. Baseline surveys done by EPA partners have revealed that the majority of leaks come from a small number of parts, mostly valves, and that once these parts are identified, cost-effective repairs can be streamlined to accomplish maximum emissions reductions and gas savings.

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[33] Draft Oil and Gas Ozone Reduction Strategy – Presented at February 26, 2008 Colorado RAQC Meeting; *See also* U.S. EPA, Install BASO Valves, *available* at http://www.epa.gov/gasstar/documents/installbaso.pdf, NEE Ex. R37.
[34] U.S. EPA, Lessons Learned from Natural Gas STAR Program, "Directed Inspection and Maintenance at Compressor Stations", *available* at http://www.epa.gov/gasstar/documents/ll_dimcompstat.pdf, NEE Ex. R38.

8. Replacing Compressor Rod Packing From Reciprocating Compressors.

Reciprocating compressors are one of the largest sources of methane emissions at natural gas compressor stations. Methane emissions are produced by leaks in the piston rod packing systems used in the compressors—especially from older systems. Replacing compressor rod systems reduces methane emissions, increases savings, and results in greater operational efficiencies and equipment life-spans. Average gas savings equal $6,055 a year and far exceed the $540 implementation cost and the payback is two months.[35] California has proposed installing compressor rod packing systems as one strategy for reducing emissions from the state's oil and natural gas transmission industry. This, along with other strategies such as improving operating practices when compressors are taken off-line and replacing old flanges and fittings along pipeline, are expected to yield 0.9 MMTCO$_2$e annually and save the oil and gas industry $17 million in annualized net savings.[36]

9. Replacement of Wet Seals with Dry Seals on Wet Seal Centrifugal Compressors

Centrifugal compressors are widely used throughout the natural gas production and transmission sectors. Seals on rotating shafts are used to prevent natural gas losses from compressor casing. Many of these seals use high-pressure oil as a barrier against escaping gas. These types of seals, referred to as "wet" seals, produce methane emissions when the circulating oil is stripped of the gas it absorbs. Dry seals use natural gas instead of oil to prevent gas losses. They also have lower power requirements, improve compressor and pipeline operating efficiency and performance, enhance compressor reliability, and require significantly less maintenance. A dry seal can save about $315,000 per year and pay for itself in as little as 11 months. One

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[35] U.S. EPA, Lessons Learned from Natural Gas STAR Partners, "Reducing Methane Emissions from Compressor Rod Packing Systems", *available* at http://www.epa.gov/gasstar/documents/ll_rodpack.pdf, NEE Ex. R39.
[36] California's Climate Change Scoping Plan, V. 1 of Appendices, http://www.arb.ca.gov/cc/scopingplan/document/appendices_volume1.pdf, C154.

Natural Gas STAR partner who installed a dry seal on an existing compressor reduced emissions by 97 percent, from 75 to 2 Mcf per day, saving almost $187,000 per year in gas alone.[37]

10. Lowering Gas Line Pressure with Pump-down Techniques

Routine maintenance and repair of natural gas pipelines can produce significant fugitive emissions. Methane is often vented during pipeline repairs and maintenance in order to depressurize the pipeline. In 1998, fugitive emissions from such repair and maintenance flaring equaled approximately 9 bcf of methane.[38] Instead of venting methane to reduce gas pressure operators can utilize in-line compressors (pump-down techniques). Using in-line compressors requires no capital costs and the payback is immediate.[39] According to EPA, on average, up to 90% of gas in pipelines can be recovered for sale instead of vented. EPA partners have reported average yearly savings of $600,000, and transmission sector partners in 1998 saved over $3 million, by using pump-down techniques to lower gas pressure during routine maintenance and repairs.[40]

II. GANTNER AND SMITH CLAIM THAT THERE ARE NO OPPORTUNITES TO REDUCE CO_2 EMISSIONS FROM COMPRESSOR ENGINES

1. Replacing Internal Compressor Combustion Engines with Electric Motors

Replacing natural gas-fired reciprocating internal combustion ("RICE") engines with electric motors to operate compressors could dramatically decrease CO_2 emissions at wellheads and compressor stations. According to a recent report by the current U.S. Environmental Protection Agency Regional Administrator for Region 6, Al Armendariz, "[T]he use of electric

[37] U.S. EPA, Lessons Learned from Natural Gas STAR Partners, "Replacing Wet Seals with DRY Seals in Centrifugal Compressors", available at http://www.epa.gov/gasstar/documents/ll_wetseals.pdf, NEE Ex. R40.
[38] U.S. EPA, Lessons Learned from Natural Gas STAR Partners, "Using Pipeline Pump-Down Techniques to Lower Gas Line Pressure Before Maintenance", 1, *available* at http://www.epa.gov/gasstar/pdf/lessons/ll_pipeline.pdf, NEE Ex. R41.
[39] *Id.*
[40] *Id.*

motors instead of internal combustion engines to drive natural gas compressors is not new to the natural gas industry, and numerous compressors driven by electric motors are operational throughout Texas."[41] Mr. Armendariz's report estimated that switching from natural gas to electric-driven RICE could result in a net savings of $12,000 per each 500 horsepower engine. Both the capital costs ($52,000 vs. $74,000) and operating and maintenance costs ($6,200 vs. $35,000) of an electric-driven engine are less than those of a natural gas-fired engine.

One important factor in comparing the relative GHG emissions of a natural gas versus electric-driven motor is the source of the electricity. Mr. Gantner and Mr. Smith testified that electric-driven motors produce more GHG emissions than one powered by natural gas.[42] This testimony assumes that coal-fired power plants provide the electricity used to power the RICE. This is an untenable assumption given that many generators of electric power are increasingly switching to alternative forms of power generation such as renewables and natural gas. Moreover, the current rules, if adopted, would require additional GHG reductions from electric power generators, thereby decreasing the GHG emissions associated with the use of electric-driven motors used at wellheads and compressor stations.

III. GANTNER AND SMITH CLAIM THAT IMPLEMENTATION OF THE PROPOSED RULE WILL RESULT IN PRODUCTION DECREASES AND WELL-SHUT INS.

In 2009 Colorado implemented comprehensive rules to regulate oil and natural gas exploration and production activities, including air emissions, in the state. During the rule-making process, industry was highly critical of these rules, claiming that greater regulation would result in an exodus of oil and gas companies from the state and a marked drop in production. These worst-case scenarios have not come to pass. According to the director of the

[41] Armendariz, *supra* note 4 at 29.
[42] Gantner, at 13; Smith at 11.

Colorado Oil and Gas Commission, Colorado is on track to issue the second highest number of oil and gas permits to drill in the state's history.[43]

[43] Dennis Webb, "Colorado's gas permits lead region", The Daily Sentinel (July 8, 2010), http://www.gjsentinel.com/news/articles/colorados_gas_permits_lead_reg/. *See also* COGCC Staff Report, 17 (July 8, 2010) (listing 2009/2010 Applications for Permit to Drill).