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FUGITIVE METHANE EMISSIONS FROM OIL AND GAS OPERATIONS

HEARING

BEFORE THE

SUBCOMMITTEE ON OVERSIGHT

OF THE

COMMITTEE ON
ENVIRONMENT AND PUBLIC WORKS
UNITED STATES SENATE

ONE HUNDRED THIRTEENTH CONGRESS

FIRST SESSION

NOVEMBER 5, 2013

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NOVEMBER 5, 2013

OPENING STATEMENTS

WITNESSES

FUGITIVE METHANE EMISSIONS FROM OIL AND GAS OPERATIONS

TUESDAY, NOVEMBER 5, 2013

U.S. SENATE,
COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS,
SUBCOMMITTEE ON OVERSIGHT,
Washington, DC.

The Subcommittee met, pursuant to notice, at 2:29 p.m. in room 406, Dirksen Senate Office Building, Hon. Sheldon Whitehouse (chairman of the Subcommittee) presiding.

Present: Senators Whitehouse, Vitter, and Inhofe.

OPENING STATEMENT OF HON. SHELDON WHITEHOUSE, U.S. SENATOR FROM THE STATE OF RHODE ISLAND

Senator WHITEHOUSE. Good afternoon, everyone, and thank you for being here. I am delighted to be hosting this hearing of our Subcommittee, and I particularly want to welcome our distinguished ranking member back. It is good to see him here and in such good health.

Our topic today is fugitive methane. As we know, methane is the most abundant component of natural gas, and burning natural gas for energy produces the beneficial effect of less carbon dioxide than burning either oil or coal. So that is a positive. And both President Obama and the gas industry have both clearly made the point that natural gas is a step toward a lower carbon energy future.

The American Gas Association's Web site says in most applications, using natural gas produces less carbon dioxide, which is the primary greenhouse gas, and, it adds, using natural gas to replace less environmentally benign fuels can help address greenhouse gas emissions.

And, of course, all of that is true, but methane itself, when left unburned, is a potent greenhouse gas. The IPCC estimates methane is 28 times more potent than carbon dioxide over 100 years and 84 times more potent over 20 years. It is clear that methane causes much more warming than carbon dioxide, particularly in the near term. The methane emissions that are not burned can actually offset, and more, the carbon benefits we get replacing oil and coal with natural gas.

According to EPA—and I want to welcome our EPA witness, Sarah Dunham, here—methane is the second most abundant greenhouse gas emitted by human activities after carbon dioxide, and almost a third of methane emissions in the U.S. come from petroleum and natural gas systems.

Methane, as a byproduct of oil drilling, is often vented directly into the atmosphere, unburned. There is a lot of it that goes out. Flaring of this unwanted natural gas in the bake and shale formation in the Northern Great Plains has been estimated to be costing landowners, who receive royalties based on the value of the resources collected from their land, about $100 million per month in lost royalties.

Even in the natural gas sector, where methane is the product and not a byproduct, significant amounts are emitted unintentionally through leaks or through inefficient drilling practices. In fact, 3 years ago the Government Accountability Office estimated that around 40 percent of the natural gas vented and flared on offshore Federal leases could be economically captured with currently available control technologies.

Domestic natural gas production is expected to grow by about 44 percent from 2011 through 2040, so fugitive methane will pose an ever greater risk to the environment and to the bottom line of natural gas companies and mineral rights owners.

But there are real opportunities here for producers and the environment. Two of our witnesses, Dr. David Allen of the University of Texas and Dr. A. Daniel Hill of Texas A&M, worked with a team of other scientists on a study demonstrating the promise of cost-effective technologies that significantly lower fugitive methane.

Research also shows that broad application of more efficient practices, such as those used by natural gas companies like Southwestern, have immediate and significant economic and environmental benefits. To be sure, implementing fugitive methane capture technologies faces economic, logistical, and legal obstacles. Nonetheless, there is evident potential for economically attractive ways to reduce fugitive methane within the oil and gas sector.

I want to thank all of our witnesses for their testimony, and I want to particularly thank our ranking member, Senator Inhofe, and also Senator Vitter of Louisiana for being here today. Today's discussion, I hope, will help Congress and the Administration better understand fugitive methane and develop win-win policies that help industry and the environment.

Now I will turn for opening remarks to our ranking member, Senator Inhofe.

OPENING STATEMENT OF HON. JAMES M. INHOFE, U.S. SENATOR FROM THE STATE OF OKLAHOMA

Senator INHOFE. I appreciate it, Mr. Chairman. Thank you. Thank you very much. This is one of the areas where we are going to find a lot of agreement with each other. And when you talk about a win-win situation, I think we are looking at one that might be.

Again, I want to welcome Sarah Dunham. She and I got to know each other in my office back during the confirmation time of Gina.

This issue is something I have been involved with for quite a number of years. Data started being collected about the time around the Natural Gas STAR Program, when it started. At that time, I chaired this Committee. The Natural Gas STAR is a voluntary program designed to allow industry to collaborate and share best practices to reduce emissions from production activities. So you had a lot of cooperation there between industry and the EPA.

We all know that oil and gas firms already have an incentive to reduce methane emissions. Methane is natural gas. If I were on the board of directors, as all other directors would feel, they don't want to waste this stuff; it has a value to it. So we are all together on that.

The Natural Gas STAR was all about EPA working collaborative with industry to help them collect the data and share best practices. It was a common goal, so everyone cooperated. Unfortunately, the EPA used the category of data it collected through the Natural Gas STAR program to justify some of its new oil and gas regulations. To make matters worse, EPA increased their emission estimate by assuming that methane is vented during the hydraulic fracturing process whenever there is not a State law mandated that it be flared, and that simply is not true.

I wrote a letter pointing this out as a problem back in April, about a year and a half ago. The Agency has gone ahead and finalized that rule anyway. Since then, the EPA has started to make some modifications to its inventory of methane emissions from oil and gas operations, but it has come only as a result of some of our personal attention to this matter.

I discussed this at great length with Gina McCarthy during her confirmation process, and once at a time when Ms. Dunham was there in her office, in present. I am very appreciative that she made some adjustments, which she did. I remember we had some stakeholders in the room at that time and she made some adjustments, but even then we still have major questions about the inventory data EPA had on emissions during the hydraulic fracturing process.

Industry had regularly communicated to me that the estimates from EPA were too high, which was contributing to the alarm surrounding the hydraulic fracturing process. A few weeks ago I think we were vindicated when we had the study the chairman referred to. The University of Texas, in conjunction with the Environmental Defense Fund, releasing a study that showed methane emissions during the hydraulic fracturing process had been overestimated by the EPA by 50 times. Not double, not triple, not 10 times; 50 times.

This study relied on real measurements, as opposed to EPA's general computer modeling estimates, so the new data we have now is significantly more trustworthy than we had before. And during the question and answer, of course, I am going to try to see where we are right now in considering this new data as opposed to some of the computer modeling that we had before.

Fortunately, industry has made significant headway toward reducing even those emissions further. The industry is known for its world class research and development practices and partnerships with leading universities around the world and, as a result, newer technology and process are constantly being developed.

If a firm finds a better way to recover a resource, without losing it to the atmosphere, they are going to do it. As I said, it is to their benefit to do it. Still, some critics have raised the concerns about the amount of flaring that is going on in North Dakota and other regions that are being targeted for their rich deposits of oil, but often yield natural gas too. In many of these cases the companies simply cannot immediately justify the gathering network of pipelines needed to capture the gas and transport it to the market. Since gas isn't liquid, it is a lot harder to move around, to transport.

One of the best ways that we could help the situation is to allow a widespread LNG exports, which are currently restricted by the Department of Energy, and if we were to do that, then demand for natural gas, which is currently very low relative to the supply that is out there today, would become more solid and more of these gathering networks could be justified, which would reduce flaring and increase domestic gas supply. So, again, that would be a truly win-win situation.

So regardless, it is crucial that EPA have the most up to date and accurate information in its methane emissions inventory. It is my hope that they will be able to immediately make some adjustments in light of the recent University of Texas EDF study.

Thank you, Mr. Chairman.

Senator WHITEHOUSE. Thank you, Chairman.

I invite Senator Vitter to make any opening remarks he may care to make.

OPENING STATEMENT OF HON. DAVID VITTER, U.S. SENATOR FROM THE STATE OF LOUISIANA

Senator VITTER. Thank you, Mr. Chairman. I would just like unanimous consent to submit my opening statement for the record.

Senator WHITEHOUSE. Without objection.

Senator VITTER. And then I will summarize it very briefly.

I certainly want to associate myself with Senator Inhofe's remarks. This is important because this activity, this oil and gas activity, and particularly fracking, is at the center of the biggest positive development in our economy in the last decade, and it is creating good paying jobs, lower energy prices, increased energy security, revitalized manufacturing. So that is important for our economy and it is important, therefore, to get this right based on the real science.

I also want to underscore how important it is that we talk about the University of Texas Environmental Defense Fund collaborative study, which is the first study, as Senator Inhofe said, to base measurements on actual production sites, actual measurements of 190 production sites, not hypothetical extrapolations or computer models. Again, as Senator Inhofe said, that study underscores how off the EPA has been on this issue.

So I look forward to focusing on that so that we can get this right based on the science, do the responsible thing, and do it in a way that allows us to continue with this real positive game changer, building American jobs.

Thank you.

[The prepared statement was not received at time of print.]

Senator WHITEHOUSE. Thank you, Senator.

I am now pleased to introduce our first witness, Ms. Sarah Dunham, who is EPA's Director of their Office of Atmospheric Programs within the Office of Air and Radiation. She is here to provide an overview of the Administration's work on fugitive methane emissions. I am encouraged that the President's Climate Action Plan includes the development of an interagency methane strategy and that EPA will be leading that team, and I look forward to learning more about the process and the other work being done by EPA to address fugitive methane.

Ms. Dunham, welcome and please proceed.

STATEMENT OF SARAH DUNHAM, DIRECTOR OF THE OFFICE OF ATMOSPHERIC PROGRAMS, OFFICE OF AIR AND RADIATION, U.S. ENVIRONMENTAL PROTECTION AGENCY

Ms. DUNHAM. Thank you. Good afternoon, Chairman Whitehouse and Ranking Members Vitter and Inhofe and members of the Subcommittee. I appreciate the opportunity to testify today regarding methane, a potent greenhouse gas.

My name is Sarah Dunham and I am the Director of the Office of Atmospheric Programs in the Office of Air and Radiation at the U.S. Environmental Protection Agency. The Office of Atmospheric Programs works to protect the ozone layer, improve regional air quality, and address climate change. My testimony today will focus on the importance of continued methane emission reductions to address climate change.

There is overwhelming scientific evidence that climate change is happening, that human activity is largely responsible, and that, if left unchecked, the impacts will be severe. Efforts to reduce carbon pollution, including short-lived gases such as methane, are critically important to public health and the environment.

Although the majority of greenhouse gas emissions consist of carbon dioxide, other powerful greenhouse gases significantly contribute to climate change, including methane, which is also an ozone precursor. The latest Intergovernmental Panel on Climate Change assessment report estimates the 100-year warming influence from one ton of methane is 28 times greater than from one ton of carbon dioxide. In 2010, methane emissions accounted for 14 percent of global greenhouse gas emissions and approximately 9 percent of U.S. greenhouse gas emissions. However, total U.S. anthropogenic methane emissions are projected to increase by 3 to 9 percent by 2030, compared to 2010 emissions levels.

Methane is primarily released from six sectors: natural gas systems, petroleum systems, agriculture, landfills, coal mining, and municipal wastewater. The EPA provides annual national methane emissions estimates for each sector in the Inventory of U.S. Greenhouse Gas Emissions and Sinks. Along with a number of other organizations, we continue to work to improve measurement methodologies and emissions estimates. There have been several recent studies and analyses that help to improve emissions estimates in the natural gas sector. The EPA has reviewed and used these sources, along with data from the Greenhouse Gas Reporting Program, to update the most recent Inventory estimates for this sector. The EPA will continue to review new data and analyses to ensure that the Inventory reflects industry practices.

Since the 1990s, the EPA, in partnership with industry, has been working with great success to reduce methane emissions domestically through programs such as Natural Gas STAR, Ag STAR, the Coalbed Methane Outreach Program, and the Landfill Methane

Outreach Program. These programs focus on removing market barriers and increasing the use of cost-effective emission reduction technologies.

We also expect significant domestic methane emissions reductions as a co-benefit from Clean Air Act regulations, including the Oil and Gas New Source Performance Standards for Volatile Organic Compounds. The EPA estimates that the Oil and Gas New Source Performance Standards, finalized in 2012, will result in up to 1 million to 1.7 million tons of methane reduced annually.

Additionally, the President's Climate Action Plan, issued in June of this year, calls for broad Federal activities to address climate change, including the development of a comprehensive, interagency strategy to address methane emissions. The EPA is currently working with other agencies to assess emissions data, address data gaps, and identify opportunities to further reduce methane emissions through incentive-based programs and existing authorities.

To conclude, reducing methane emissions is critical to mitigating the impacts of global climate change. We have made progress, but there is more to be done and the interagency strategy that the President's Plan calls for will put us on a solid path forward to realize even further carbon pollution reductions.

Thank you again for the opportunity to testify, and I look forward to answering your questions.

[The prepared statement of Ms. Dunham follows:]

Statement of Sarah Dunham
Director, Office of Atmospheric Programs
U.S. Environmental Protection Agency

Hearing on
"Fugitive Methane Emissions from Oil and Gas Operations"
Subcommittee on Oversight
Committee on Environment & Public Works
U.S. Senate
November 5, 2013

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Methane Emissions and Climate Change

There is overwhelming scientific evidence that climate change is happening, that human activity is largely responsible, and that if left unchecked, the impacts will be severe. Efforts to reduce carbon pollution, including short-lived gases such as methane, are critically important to public health and the environment.

Although the majority of greenhouse gas emissions consist of carbon dioxide, other powerful greenhouse gases significantly contribute to climate change, including methane, which is also an ozone precursor. The latest Intergovernmental Panel on Climate Change assessment report estimates the 100-year warming influence from one ton of methane is 28 times greater than from one ton of carbon dioxide. In 2010, methane emissions accounted for 14% of global greenhouse gas emissions and approximately 9% of U.S. greenhouse gas emissions.[1] However, total U.S. anthropogenic methane emissions are projected to increase by 3-9% by 2030, compared to 2010 emissions levels.

Methane Emissions Data

Methane is primarily released from six sectors: natural gas systems, petroleum systems, agriculture, landfills, coal mining, and municipal wastewater. The EPA provides annual national methane emissions estimates for each sector in the Inventory of U.S. Greenhouse Gas Emissions and Sinks. Along with a number of other organizations, we continue to work to improve measurement methodologies and emissions estimates. There have been several recent studies and analyses that help to improve emissions estimates in the natural gas sector. The EPA has reviewed and used these sources, along with data from the Greenhouse Gas Reporting Program, to update the most recent Inventory estimates for this sector. The EPA will continue to review new data and analyses to ensure that the Inventory reflects industry practices.

EPA Methane-Related Activities

Since the 1990s, the EPA, in partnership with industry, has been working with great success to reduce methane emissions domestically through programs such as Natural Gas STAR, Ag STAR, the Coalbed Methane Outreach Program, and the Landfill Methane Outreach Program. These programs focus on removing market barriers and increasing the use of cost-effective emission reduction technologies.

[1] These emissions percentages are from the U.S. Greenhouse Gas Inventory, which uses the methane global warming potential of 21 from the IPCC Second Assessment Report (SAR).

We also expect significant domestic methane emissions reductions as a co-benefit from Clean Air Act regulations including the Oil and Gas New Source Performance Standards for Volatile Organic Compounds. The EPA estimates that the Oil and Gas New Source Performance Standards, finalized in 2012, will result in up to 1.0 to 1.7 million tons of methane reduced annually.

President's Climate Action Plan

Additionally, the President's Climate Action Plan issued in June of this year calls for broad federal activities to address climate change including the development of a comprehensive, interagency strategy to address methane emissions. The EPA is currently working with other agencies to assess emissions data, address data gaps, and identify opportunities to further reduce methane emissions through incentive-based programs and existing authorities.

Conclusion

To conclude, reducing methane emissions is critical to mitigating the impacts of global climate change. We have made progress, but there is more to be done and the interagency strategy that the President's Plan calls for will put us on a solid path forward to realize even further carbon pollution reductions.

Thank you again for the opportunity to testify. I look forward to answering your questions.

Environment and Public Works Committee Hearing
November 5, 2013
Follow-Up Questions for Written Submission

Questions for Dunham

Questions from: Senator David Vitter

1. **The recent EPA regulations on the oil and gas sector were a result of a lawsuit filed by environmentalists alleging that EPA missed statutory deadlines for reviewing and updating the previous NSPS and NESHAP standards for the oil and gas sector, is that correct?**

The Clean Air Act requires the EPA to set new source performance standards (NSPS) for industrial categories that cause, or significantly contribute to, air pollution that may endanger public health or welfare and set standards for the emissions of air toxics, also called hazardous air pollutants that are known or suspected of causing cancer and other serious health effects (NESHAP). The agency is then required to review the NSPS and conduct a technology review of the NESHAP every eight years, and also conduct a residual risk review one time, within eight years after the NESHAP is issued. The previous NSPS, for volatile organic compounds and sulfur dioxide, were issued in 1985 and the NESHAP for both oil and natural gas production and natural gas transmission and storage were issued in 1999. In 2009, since the agency had not taken the required actions, Wild Earth Guardians and San Juan Citizens Alliance sued EPA to review the NSPS and to conduct the residual risk and technology reviews of the NESHAP as required by the Clean Air Act.

The EPA agreed to a schedule for review and notice and comment rulemaking to fulfill that statutory requirement, which we met with final rules published in the Federal Register on August 16, 2012 (77 FR 49489). The "Oil and Natural Gas Sector: New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Reviews" had several components. First, it revised the NSPS for volatile organic compounds at onshore natural gas processing plants and revised the NSPS for sulfur dioxide emissions from natural gas processing plants. Second, it established NSPS for certain oil and gas operations not covered by the existing standards. Third, it finalized the residual risk and technology review for the Oil and Natural Gas Production source category and the Natural Gas Transmission and Storage source category.

a. **Because this lawsuit was centered around updating existing emissions standards, EPA did not affirmatively find it appropriate to revise the oil and gas NSPS to directly regulate methane emissions?**

In the final rule, EPA chose to continue to evaluate the appropriateness of regulating methane with an eye toward taking additional steps if appropriate. The agency noted that the collection of further data through the Greenhouse Gas Reporting Program (GHGRP) and other data sources would help EPA evaluate whether it is appropriate to directly regulate methane from oil and gas sources covered by the 2012 rulemaking.[1]

2. Does the Agency have any guidance or cut off as to what point a "co-benefit" is actually no longer a "co-benefit?" For example, the NSPS rule for oil and gas finalized by EPA is largely justified by the reduction of methane, a "co-benefit." These methane reductions are over 90 times greater than the reductions of hazardous air pollutants the rule primarily seeks to regulate. At what point in a rule like this does the "co-benefit" actually become the subject of the regulation? If a "co- benefit" results in 10 times the emissions reductions than what a rule is meant to address, is it still a "co-benefit"? What about 50 times?

Pollution controls often reduce multiple pollutants, leading to significant co-benefits from the application of those controls. For example, in the oil and gas sector, the use of reduced emissions completions of hydraulically fractured natural gas wells reduce VOC emissions and also provide significant methane co-benefits at no additional cost. However, these methane co-benefits were not considered when EPA determined the cost-effective level of control in setting standards in the 2012 rulemaking which reflect the best system of emission reduction for VOC. The reductions of pollutants beyond those directly targeted by the regulation are considered co-benefits regardless of their magnitude. Best practices for economic analysis and guidance from the Office of Management and Budget require that the EPA consider all benefits of a regulation, including ancillary benefits.

a. Methane reduction is clearly a large "co-benefit" of the newly updated air rules for the oil and gas industry. Should EPA move to further regulate air emissions from the oil and gas industry – particularly methane specific regulations – would the Agency count reductions in methane emissions from the current rules as benefits for future new rules?

   No. When the EPA calculates benefits for a new regulation, those benefits are above and beyond reductions the agency previously estimated for other pollution control regulations that are already "on the books."

b. Can EPA commit to that any future air rules related to the oil and gas industry, for example one specifically regulating methane, will not double count the benefits already used by the Agency in other rules to justify costs or inflate

[1] "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule," 77 *Federal Register* 159 (August 12, 2012), *pp 49513.*

benefits that are already in place?

Yes. When the EPA calculates benefits for a new regulation, those benefits are above and beyond reductions the agency previously estimated for other pollution control regulations that are already "on the books."

3. **EPA received a notice of intent to sue from seven northeastern – largely non-oil and gas producing-States Attorney Generals to force the agency to create additional regulations on the oil and gas industry in order to directly regulate methane. What are EPA's plans in regards to additional rulemakings on methane or other potential air emissions related to the oil and gas industry? Are there any efforts underway now?**

EPA received the "Clean Air Act Notice of Intent to Sue for Failure to Determine Whether Standards of Performance Are Appropriate for Methane Emissions from Oil and Gas Operations, and to Establish Such Standards and Related Guidelines for New and Existing Sources." The notice of intent to sue was submitted by the states of New York, Connecticut, Delaware, Maryland, Massachusetts, Rhode Island and Vermont on December 11, 2012. At this time no decisions have been made regarding EPA's response to this notice of intent to sue.

Additionally, after promulgating final actions in 2012, EPA received 11 petitions for reconsideration on both the NSPS and the NESHAP. The petitions were submitted by industry, states and NGOs. The agency has agreed to respond to those petitions, and is currently evaluating the issues that were raised. One petitioner asked EPA to reevaluate the decision not to regulate methane under the NSPS. No decisions regarding regulation of methane have been made. The EPA plans to propose reconsiderations of both the NSPS and NESHAP as soon as possible.

a. **Given the fact that EPA's air rules on the oil and gas industry which the Agency contends will have significant methane emissions reductions have not been fully implemented yet, can the Agency commit to not moving forward with new regulations until a recent NSPS and NESHAP are fully implemented and EPA has a better idea of the state of emissions at that time?**

On September 23, 2013, EPA published final time-critical updates to the NSPS for storage tanks in the oil and natural gas sector. The changes reflect recent information showing that more higher-volume storage tanks will be coming on line than the agency originally estimated. Additionally, the agency is in the process of addressing several additional issues raised in the 2012 petitions for reconsideration of both the NSPS and the NESHAP that the Agency believes warrant reconsideration. EPA intends to issue proposals to address these issues as soon as possible. The agency continues to work through the complex issues that were raised but has not determined which issues for which reconsideration should be granted. As a result, the agency cannot commit to a specific timeline; therefore, it is uncertain whether these reconsiderations will be issued before or after the full implementation of the 2012 NSPS and NESHAP.

b. **The UT-EDF study used real world data to clearly show that EPA's methane emissions estimates from hydraulically fractured wells were grossly overinflated. Will EPA take this empirical data into consideration prior to crafting any potential new emissions regulations with regard to hydraulically fractured wells?**

EPA is currently evaluating the UT Austin-EDF study on methane emissions from the gas industry, and is seeking stakeholder input on use of the study data. Overall, this study found that total methane emissions from natural gas production, from all sources measured in the study, were comparable to the most recent EPA estimates.[2]

Research studies like the UT Austin-EDF study will add to EPA's knowledge base of this sector's GHG emissions. EPA is encouraged that more methane emissions measurement data for the gas industry are now available to the public and to EPA as we consider and/or craft any future regulations.

c. **Can you commit that if EPA moves further to regulate air emissions from the oil and gas industry the Agency will not rely on their outdated data but rather use actual emissions that among other things have shown significantly less real emissions from hydraulic fracturing?**

The natural gas sector has experienced significant growth and changes in industry practices in recent years, and the EPA will continue to evaluate emissions estimates for this sector. There are a variety of existing and planned oil and natural gas emissions studies and data collection efforts underway. As always, the EPA is committed to reviewing all new data (such as data from the Greenhouse Gas Reporting Program and the UT Austin-EDF study) to ensure its emissions estimates reflect the most robust data and information available.

In support of the Administration's Strategy to Reduce Methane Emissions, on April 15, 2014, EPA released a series of five white papers on potentially significant sources of volatile organic compound (VOC's) and methane in the oil and gas sector for input from a panel of independent experts. The white papers focus on technical issues

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[2] See page 1 of (Allen et al. 2013). Measurements of methane emissions at natural gas production sites in the United States. PNAS. vol. 110 no. 44.

covering emissions and mitigation techniques. EPA will use the papers, along with input from the experts and technical input and data from the public to determine how to best pursue further reductions from these sources. The papers do not draw policy conclusions.

4. What is the status of the Comprehensive Interagency Methane Strategy announced by the President in June? Who is involved, and can you tell me when the strategy will be released?

The EPA and the Departments of Agriculture, Energy, Interior, and Transportation worked together to develop a comprehensive Strategy to Reduce Methane Emissions, which was released by the Administration on March 28, 2014.

a. Is there any public or stakeholder involvement in this strategy? If so please describe.

The Secretary of Energy is convening a series of Roundtable discussions that began in March, on issues related to methane emissions, with leaders from industry, state governments, academia, non-governmental organizations, and labor. In addition, in the spring of 2014, EPA will begin to engage industry, states, and other key stakeholders on ways to enhance the Natural Gas STAR program, and will formally launch the new partnership by the end of 2014.

b. What is EPA's role?

The President's Climate Action Plan commits the Administration to making additional progress in reducing methane emissions by developing an interagency, multi-sector methane strategy for "assessing current emissions data, addressing data gaps, identifying technologies and best practices for reducing emissions, and identifying existing authorities and incentive-based opportunities to reduce methane emissions."

A number of agencies including the Environmental Protection Agency, the Department of Energy, the Department of Agriculture, the Department of Interior, the Department of Transportation, and the Department of Commerce worked together to develop a comprehensive methane strategy. The EPA has been a key participant and contributor, providing input based on our experience working with the US National Greenhouse Gas Emissions Inventory, the Greenhouse Gas Reporting Program, and our voluntary and regulatory programs.

In implementing this interagency methane strategy, the Obama Administration will work collaboratively with state governments, as well as the private sector, to reduce emissions across multiple sectors, improve air quality, and achieve public health and economic benefits.

5. **In the President's Climate Action Plan when addressing the issue of reducing methane emissions the plan states "when it comes to the oil and gas sector, investments to build and upgrade gas pipelines will not only put more Americans to work, but also reduce emission and enhance economic productivity." Does EPA have a role in the permitting of natural gas infrastructure? Does EPA share the President's goal of expeditiously building more natural gas pipelines and infrastructure?**

The Administration continues to believe that our abundant domestic natural gas resources have an important role to play in the transition to a clean energy economy. The EPA does not directly permit natural gas infrastructure development, but does play a role in permitting air emissions from a limited number of sources that make up the natural gas infrastructure. For example, new or modified major sources of air emissions, such as the large compressors used in natural gas transmission pipelines, could be required to obtain a pre-construction permit prior to construction. The level of emissions at which such a permit is required varies depending on the air quality of the area in which the source will locate. This federal permit program, known as new source review (NSR), is typically implemented by state or local permitting authorities under the rules approved into their State Implementation Plans (SIPs). In some jurisdictions, such as Indian Country, EPA is the permitting authority. After construction, these major sources may be required to obtain an operating permit under title V of the Clean Air Act. Like the NSR program, the title V permit would typically be issued by the state, local or tribal agency responsible for the area in which the source is located. The Agency is committed to improving our understanding of methane emissions and working with industry to identify cost-effective reduction opportunities in order to ensure that new oil and gas development is done in a commonsense way that protects the environment, communities, and the public.

Senator WHITEHOUSE. Thank you, Ms. Dunham. I appreciate your testimony here. You concluded by saying that the EPA estimates that the Oil and Gas New Source Performance Standards finalized in 2012 will result in between 1 million and 1.7 million tons of methane reduced annually. What are the technologies that are required to achieve that? Are we dealing with very experimental or cutting-edge technologies or is this pretty established stuff?

Ms. DUNHAM. Thank you for that question. The New Source Performance Standard that I referred to really builds upon and requires a set of technologies and best practices that have been the industry has already proven are cost-effective and very effective at reducing methane emissions. A number of technologies that the industry leaders have been deploying for a number of years and that we have been working with industry through our Gas STAR program to show that they really do cost-effectively reduce and capture emissions. It is those types of technologies that form, really, the heart of the requirements under the New Source Performance Standard.

Senator WHITEHOUSE. So they are both established technologies and cost-effective for the implementing companies, not counting the social effects or the social benefits. From a pure company point of view they are cost-effective?

Ms. DUNHAM. That is true. The cost-effectiveness largely comes from capturing the natural gas emitted during the process and using that, as you know, as a valuable energy resource.

Senator WHITEHOUSE. Do you estimate how much these reductions will save industry participants each year?

Ms. DUNHAM. Yes, sir. We have estimated for when the rules have been fully implemented, in 2015 and beyond, that the rules show a savings of between $11 million and $19 million a year, again, to the previous point, largely from reducing the waste of the valuable resource of natural gas.

Senator WHITEHOUSE. And do you think that the New Source Performance Standards have driven down actual fugitive methane emissions from oil and natural gas systems at this point?

Ms. DUNHAM. We are certainly working with industry collaboratively as industry is working to implement these regulations. A number of the dates haven't yet been fully realized in terms of when the compliance requirements are, so we don't have in our data collection, for example, our greenhouse gas reporting program, where some of the data would show up, we don't have that yet to show it, but we certainly are hopeful and we expect that the benefits that we projected under the rule will be achieved.

Senator WHITEHOUSE. You all at EPA are the lead on the President's Climate Action Plan. What can you tell us about what you expect EPA's role to be in terms of how you expect the process to work and any timeline or deliverables that you have in mind at this point?

Ms. DUNHAM. One point to point out is we do, through our partnership programs, largely, have a long history of working with industry, again, on a very collaborative and partnership basis across a number of different sectors to help reduce methane emissions, so we are bringing that into the interagency discussions. But the development of the methane strategy called for in the President's Climate Action Plan is being led through the White House through the collaboration of multiple Federal agencies, because I think, as you pointed out, there are multiple agencies who have a role here in looking at reducing methane emissions from multiple sectors.

Senator WHITEHOUSE. And what do you think your timeline is likely to be?

Ms. DUNHAM. I don't have a timeline right now, but I think what I can do is take back that question and that interest back, particularly to the interagency group and the White House, and we can follow up.

Senator WHITEHOUSE. Good. Anything on like timeline, process, and deliverable points where it will help us kind of mark your progress as you go forward I think would be very helpful.

Ms. DUNHAM. OK.

Senator WHITEHOUSE. Senator Inhofe.

Senator INHOFE. Thank you, Mr. Chairman. Again, I welcome our witness here. You have been career and you have been through this. You were in the new STAR program and were very familiar with the benefits, and with the cooperation that we have historically had, at least I believe at that time, we don't have quite that same cooperation now, from my estimation.

Now, on this program that was put together by the University of Texas and the EDF, have you looked at this? Have you formed any personal evaluations as to the accuracy of the results that they came up with? Have you looked at this? I guess I will rephrase it a different way. Do you object to their results in any way?

Ms. DUNHAM. Well, sir, I think one of the things I noted in my testimony is that there have been, and continue to be, a number of studies in this area of measuring the emissions from the natural gas sector, and I think we see the study that you will hear about from the next panel as one of the very significant ones that is producing a lot more data in this area, so we hope to evaluate it and draw from that moving forward.

Senator INHOFE. But don't you think, though—you are talking about the University of Texas here, you are talking about the EDF. These are groups that normally would not be entrenched in one side or the other, and here they are together in agreement with each other. And the reason I bring this up, if this were like a two to one variance from what our data that was used for models, then I would feel a little bit differently about it, but right now are you currently making changes as a result of this in terms of what you are expecting from industry, in terms of your relationship with other entities and also international groups such as the United Nations? Are you sending out anything saying we are correcting errors that we made in the past, which is understandable, because this is the first time there has really been a study like this that has taken place?

Ms. DUNHAM. I think the subject of the study that was done by the University of Texas and this group is definitely an area that we have already very publicly called attention to as an area where we are seeking additional data and it would be very helpful to have additional data. So it is very timely and relevant to those sorts of efforts that we have been saying over the last year or so and particularly called out in our most recent greenhouse gas emissions inventory as an area where we were seeking additional data and looking for enough data to possibly look at different methodologies for estimating emissions from this sector. So some of the specific things that we asked for in that inventory this study is very relevant to.

Senator INHOFE. I know you know this because I have said it so many times and one time or another you have heard it. The first hydraulic fracturing that took place was in my State of Oklahoma in 1948, and I can remember the predecessor, back when Lisa Jackson was the director of the EPA, in response to the question has there ever been a documented case of contamination as a result of hydraulic fracturing, and she said no. So I am very interested in this because, as you look around, you see this huge boon that is taking place right now. It is horizontal drilling and hydraulic fracturing. Without that we probably wouldn't be having this meeting today.

So my concern is, and I was very pleased to see the results of this study that took place, that we immediately adopt this and discard anything that is in conflict with this and not continue with any kind of regulations that are underway right now until that is fully considered. Are there regulations right now that are underway or being studied by the EPA?

Ms. DUNHAM. We have a number of petitions for reconsideration and judicial review on the New Source Performance Standard that we finalized last year that I referred to, and we are continuing to evaluate those petitions and the issues that were raised in them.

Senator INHOFE. With any regulations that are currently in the planning stage, would you do an advanced notice of proposed rulemaking and allow comment to be taken on the notice to see if the regulations are even necessary or should be changed?

Ms. DUNHAM. Again, I think to the extent that we are considering additional issues, it is largely under the umbrella of the evaluation of the ongoing petitions with respect to the process with which we would move forward with. I should note that it is not my office that owns the regulatory framework; what we do, largely, is support some of the analysis and the data on those.

Senator INHOFE. Yes, but you are representing the EPA at this time.

Ms. DUNHAM. That is true.

Senator INHOFE. The last thing I wanted to mention, and maybe this would be something you might want to take for the record, because one of the things that could improve the demand certainty of natural gas is to justify more gathering lines. This gets into the somewhat controversial area of exporting LNG. Of course, there are a lot of people who are opposed to it, saying that is going to cause the price to increase here in the United States, when in fact something is going to have to be done because right now the supply and demand situation is such that we have something we could really offer in terms of the balance of trade and other things that we could be great beneficiaries of that. So do you have any comments right now in expanding the LNG exports?

Ms. DUNHAM. I do not have any comments on that.

Senator INHOFE. OK. Well, something to think about it.

Thank you, Mr. Chairman.

Senator WHITEHOUSE. You are very welcome, Senator.

I will turn to Senator Vitter.

Senator VITTER. Thank you, Mr. Chairman.

And thanks, Ms. Dunham, for your work, for being here.

The regulatory impact analysis for the final NSPS rule discusses the 2010 social cost of carbon estimates developed by the Administration's interagency working group, and this year that working group released revised social cost of carbon estimates and those are being used in a lot of EPA proposals, so they are very significant. During all your work at EPA, have you participated, or do you now, in that interagency working group work on the social cost of carbon?

Ms. DUNHAM. We have folks in my office who are part of the technical group that goes into the modeling context.

Senator VITTER. So your office certainly participates in that.

Ms. DUNHAM. It participates in the development of the analysis and the modeling.

Senator VITTER. OK. And personally have you attended meetings, provided materials, analysis during the development of those social costs of carbon estimates?

Ms. DUNHAM. I have certainly attended some meetings. There are a lot of different meetings on these, but I certainly attended some meetings that have discussed the updated social cost of carbon estimates, and particularly with respect to the technical work and the modeling and some of the differences.

Senator VITTER. Where I am going is to anyone outside the Administration, including me, this is like a black box, and we have been asking a number of legitimate questions through at least two letters about that process and about the participants, and I have just gotten no information yet. So are you aware of others who have been involved in that process?

Ms. DUNHAM. I am certainly aware of your interest in the subject and knowing more about it, so what I can do is make sure that I take that interest back in learning more about what the process was.

Senator VITTER. OK. Specifically, can you ensure that our inquiries are substantively addressed, including with a list of agency officials who have participated in that social cost of carbon process?

Ms. DUNHAM. I can certainly take your interest in getting that back to the agency.

Senator VITTER. OK. I am not so much concerned about that; I am concerned about the other direction.

Ms. DUNHAM. I understand.

Senator VITTER. Will we get anything back from EPA or the Administration?

Ms. DUNHAM. Yes. It is not my role at the Agency to speak for that, but I can take it back, your interest in it.

Senator VITTER. Well, I would specifically ask you to get those legitimate questions answered, including a list of Agency officials who have participated.

Ms. DUNHAM. Yes, sir.

Senator VITTER. Since you have been somewhat involved in the process, what officials do you know of who have participated directly?

Ms. DUNHAM. Well, I will tell you the discussions that I have been mostly involved with were really the technical and the modelers, and things like that. I know you are asking for a broader set of questions and frankly would like to defer to the Agency officials.

Senator VITTER. OK. Well, since you are the witness, I would just like to ask for you to supplement this record with a list of all officials that you know of who have participated in that.

Ms. DUNHAM. OK.

Senator VITTER. Great. Ms. Dunham, a number of us are a little concerned about the very sort of backdoor way EPA has gone at regulating methane through these lawsuits that were filed, including basically regulating it as a co-benefit. But the methane reductions, at the end of the day, are on the order of 90 times greater than the reductions of hazardous air pollutants that the rule directly seeks to regulate. Do you have any concern about that, sort of the tail wagging the dog?

Ms. DUNHAM. Well, I think for a number of sectors methane is co-emitted with volatile organic compounds and, frankly, I think we—and a number of the technologies that have been used and are used in this regulation that capture both volatile organic compounds also capture methane. So I think using this sort of model of capturing the methane as a co-benefit is a helpful one in terms of using this very valuable natural resource that is being vented to the atmosphere without these technologies.

Senator VITTER. OK.

If I can have an additional 30 seconds.

It appears EPA is also on the verge of getting sued again, probably in an attempt to force the Agency into additional regulations that more directly regulate methane. As we speak, what are EPA's plans in regard to additional rulemakings on methane?

Ms. DUNHAM. Again, particularly with respect to the oil and gas sector, that is one of the issues that we have been petitioned on for reconsideration, so we are continuing to evaluate all those issues.

Senator VITTER. Final question.

Senator WHITEHOUSE. For the record, could I just ask the witness to define the word petitioned, what she means by that so that it is clear to people following this?

Ms. DUNHAM. Yes. And maybe we can get back to you with a more formal legal definition of it, but we have petitions for reconsideration of issues under the rule, as well as petitions for judicial review of the rule. But if you want a more sort of fuller explanation of both the petitions, as well as the use of that word, we would be happy to——

Senator WHITEHOUSE. No, that is close enough.

Ms. DUNHAM. OK.

Senator VITTER. Final question. In any of that future work, will the EPA commit to using actual measurement data from actual sites like the University of Texas study—I am not suggesting that should be the entire universe—would seem to be qualitatively different and better, if it is done right, than modeling, et cetera?

Ms. DUNHAM. We absolutely agree that the more actual measurement data there is that is available, we want to use that to improve our estimates. And I would just point out that there are a number of studies, in addition to the University of Texas one, including the now 2 years' worth of greenhouse gas reporting program data that actually requires all facilities to report emissions to the Agency. That is another extremely valuable source of data for use in updating our estimates and making sure that they are based on the best available science.

Senator VITTER. OK, thank you.

Senator WHITEHOUSE. Thank you very much, Ms. Dunham. We appreciate you being here and we appreciate very much your work.

Ms. DUNHAM. Thank you.

Senator WHITEHOUSE. Enjoy the rest of the afternoon.

Ms. DUNHAM. Thank you.

Senator WHITEHOUSE. If I may take just a moment's recess while we call up the next panel of witnesses and ask the witnesses to come forward.

[Recess.]

Senator WHITEHOUSE. Good afternoon, gentlemen. Thank you all for being here. I appreciate it very much. I think what I will just do is go right across the table, starting with Dr. Allen. Dr. Allen is the Gertz Regents Professor in Chemical Engineering and the Director of the Center for Energy and Environmental Research at the University of Texas at Austin. He has authored six books and over 200 papers in areas ranging from coal liquefaction and heavy oil chemistry to the chemistry of urban atmospheres. Dr. Allen's work has focused primarily on urban air quality and the development of materials for environmental education in the past decade.

He has also developed environmental educational materials for engineering curricula and for the University's core curriculum. He was the lead investigator for the first and second Texas Air Quality Studies, which involved hundreds of researchers drawn from around the world and which have had a substantial effect on the direction of air quality policies in Texas.

He received his bachelor of science degree in chemical engineering with distinction from Cornell University. His master and Ph.D. degrees in chemical engineering were awarded by Cal-Tech in 1981 and 1983. He has held visiting faculty appointments at Cal-Tech, the University of California Santa Barbara, and at the Department of Energy, and we are pleased to welcome him here.

Dr. Allen.

STATEMENT OF DAVID ALLEN, Ph.D., GERTZ REGENTS PROFESSOR IN CHEMICAL ENGINEERING AND DIRECTOR OF THE CENTER FOR ENERGY AND ENVIRONMENTAL RESOURCES, THE UNIVERSITY OF TEXAS AT AUSTIN

Mr. ALLEN. Thank you very much for inviting me to appear in this hearing of the Environmental and Public Works Oversight Committee on methane leakage. My name is David Allen and I am a professor in the Cockrell School of Engineering and the Director of the Center for Energy and Environmental Resources at the University of Texas at Austin.

Since January 2012, I have been leading a research team funded by Environmental Defense Fund and nine natural gas producers. The nine large and mid-sized companies that have participated in this study account for 16 percent of natural gas production and roughly half of new gas well completions in the United States. The research team making the measurements consisted of personnel from UT-Austin's Cockrell School of Engineering and environmental testing firms URS and Aerodyne Research.

The team has been making measurements of methane emissions from natural gas production sites throughout the United States, in locations ranging from Pennsylvania to the Gulf Coast and Rocky Mountains. In September this year, our first results were published by the Proceedings of the National Academy of Sciences. In these brief prepared remarks I will summarize the main findings of our work to date.

The overall goal of the study was to measure methane emissions during natural gas production at a large number of recently developed sites and to assess the national implications for methane emissions of these measurements. The team performed the first-ever direct measurements of methane emissions from some of these sources.

Briefly, our study is based on measurements made at 190 production sites throughout the United States, with access provided by the nine participating energy companies.

The collaboration of the energy companies and unprecedented access to their natural gas production facilities and equipment allowed our research team to acquire direct measurements of methane emissions from natural gas production operations where hydraulic fracturing is used.

During the year-long study, the UT-led team selected times and general locations for sampling activities, and companies provided us with access to their sites. The sampling was designed to be representative of company operations in the Gulf Coast, Mid-Continent, Rocky Mountain, and Appalachian regions.

We measured methane emissions from hydraulically fractured well completions, a process that clears sand and liquids from a fractured well. For two-thirds of the completions sampled during the study, reduced emission completion equipment was used to reduce methane emissions. This equipment reduced emissions by 99 percent.

For these wells, only 1 percent of the methane leaving the well during the completion flowback was emitted to the atmosphere. Because of this equipment, our estimates of national methane emissions from well completions are significantly lower than the calendar year 2011 national emission estimates that were released by the EPA in April 2013.

We also found that emissions from certain types of pneumatic devices, which control devices such as valves on well sites, are 30 percent to several times higher than calendar year 2011 EPA estimates for this equipment. We estimate the combined emissions from pneumatics and equipment leaks account for about 40 percent of national emissions of methane from natural gas production.

We found that the total methane emissions from natural gas production from all sources measured in the study were comparable to the most recent calendar year 2011 EPA estimates.

Having summarized the findings, I will briefly comment on the manner in which the work was reviewed. The nine natural gas producers and Environmental Defense Fund provided technical reviews throughout the study. In addition, a scientific advisory panel made up of independent academic experts reviewed the study. The panel reviewed project plans before data collection, preliminary findings, and the final manuscript that was published. Prior to publication, the study also went through the peer review process of the Proceedings of the National Academy of Sciences, which involved responding to the comments of anonymous reviewers selected by the editors.

In addition, I note that our study, which focused on natural gas production, is part of a larger effort spearheaded by the Environmental Defense Fund to measure methane emissions throughout the natural gas supply chain. Results for the studies addressing other parts of the supply chain, which are being done by other investigators, will be reported during the next 12 to 18 months.

Finally, I note that the University of Texas at Austin is committed to transparency and disclosure of all potential conflicts of interest of its researchers, and for details on our disclosures I call your attention to those disclosures that appear with our published manuscript.

Thank you for the opportunity to describe our work.

[The prepared statement of Mr. Allen follows:]

Prepared Remarks for the testimony of David Allen for the methane leakage hearing of the Environment and Public Works Oversight Subcommittee of the U.S. Senate

November 5, 2013

Thank you for inviting me to appear in this hearing of the Environment and Public Works Oversight Subcommittee on methane leakage. My name is David Allen and I am a Professor in the Cockrell School of Engineering and Director of the Center for Energy and Environmental Resources at the University of Texas at Austin.

Since January of 2012, I have been leading a research team, funded by Environmental Defense Fund and nine natural gas producers. The nine large and mid-sized companies that have participated in the study account for 16% of natural gas production and roughly half of new gas well completions in the United States. The research team making the measurements consists of personnel from UT Austin's Cockrell School of Engineering and environmental testing firms URS and Aerodyne Research. The team has been making measurements of methane emissions from natural gas production sites throughout the United States, in locations ranging from Pennsylvania to the Gulf Coast and Rocky Mountains. In September of 2013, our first results were published by the *Proceedings of the National Academy of Sciences*. In these prepared remarks, I will summarize the main findings of our work to date.

The overall goal of the study was to measure methane emissions during natural gas production at a large number of recently developed sites, and to assess the national implications for methane emissions. The team performed the first-ever direct measurements of methane emissions from some of these sources.

- Our study is based on measurements made directly at 190 production sites throughout the United States, with access provided by nine participating energy companies.
- The collaboration of the energy companies and unprecedented access to their natural gas production facilities and equipment allowed our research team to acquire direct measurements of methane emissions from natural gas production operations where hydraulic fracturing is used.
- During the yearlong study, the UT-led study team selected times and general locations for sampling activities, and companies provided access to sites. The sampling was designed to be representative of company operations in the Gulf Coast, Mid-Continent, Rocky Mountain and Appalachian regions.
- We measured methane emissions from hydraulically fractured well completions, a process that clears sand and liquids from a fractured well. For two thirds of the completion flowbacks sampled during the study, reduced emission completion equipment was used to reduce methane

emissions. This equipment reduced emissions by 99 percent; for these wells, only 1% of the methane leaving the well during the completion flowback was emitted to the atmosphere. Because of this equipment, our estimates of national methane emissions from well completions are significantly lower than calendar year 2011 national emission estimates, released by the Environmental Protection Agency (EPA) in April 2013.

- We found that emissions from certain types of pneumatic devices, which control devices such as valves on well sites, are 30 percent to several times higher than calendar year 2011 EPA estimates for this equipment; we estimate that, combined, emissions from pneumatics and equipment leaks account for about 40 percent of national emissions of methane from natural gas production.
- We found that the total methane emissions from natural gas production, from all sources measured in the study, were comparable to the calendar year 2011EPA estimates.

Having summarized the findings, I will briefly comment on the manner in which the work was reviewed. The nine natural gas producers and Environmental Defense fund provided technical reviews throughout the study. In addition, a Scientific Advisory Panel made up of six independent academic experts reviewed the study. The panel reviewed project plans before data collection and preliminary findings during data collection. Its members reviewed the draft final report and co-authored the published manuscript. Prior to publication, the study also went through the peer review process of the *Proceedings of the National Academy of Sciences*, which involved responding to the comments of anonymous reviewers, selected by the editors.

In addition, I note that our study, which focused on natural gas production, is part of a larger research effort spearheaded by Environmental Defense Fund to measure methane emissions throughout the natural gas supply chain. Results for the studies addressing other parts of the supply chain will be reported during the next 12-18 months.

Finally, I note that the University of Texas at Austin is committed to transparency and disclosure of all potential conflicts of interest of its researchers. For more details, I call your attention to the disclosures that appear with our published manuscript.

Thank you for the opportunity to describe our work.

Testimony by David Allen before the Committee on Environment and Public Works, November 5, 2013

Responses to questions submitted on December 20, 2013 by Chairman Boxer and Ranking Member Vitter December 24, 2013

Questions from Senator Boxer:

1. Your published study entitled "Measurements of methane emissions at natural gas production sites in the United States," Proceedings of the National Academy of Sciences (October 29, 20013) ("UT Study") acknowledges that the Environmental Defense Fund (EDF); Anadarko Petroleum Corporation; BG Group plc; Chevron; Encana Oil & Gas (USA) Inc.; Pioneer Natural Resources Company; SWEPI LP (Shell); Southwestern Energy; Talisman Energy USA; and XTO Energy, an ExxonMobil subsidiary provided "financial support, technical advice and access to sites for sampling." Please disclose any financial support the study received from the nine natural gas companies involved.

Response: We noted the financial support for our work in our published paper and in an announcement of the study, which was released in October of 2012. As we describe in our published paper, "The sponsors [of our study] were Environmental Defense Fund (EDF), Anadarko Petroleum Corporation, BG Group plc, Chevron, Encana Oil & Gas (USA) Inc., Pioneer Natural Resources Company, SWEPI LP (Shell), Southwestern Energy, Talisman Energy USA, and XTO Energy, an ExxonMobil subsidiary. Funding for EDF's methane research series, including the University of Texas study, is provided for by Fiona and Stan Druckenmiller, Heising-Simons Foundation, Bill and Susan Oberndorf, Betsy and Sam Reeves, Robertson Foundation, Tom Steyer and Kat Taylor, and the Walton Family Foundation."

Total funding for the study was $2.35 million, provided in roughly equal amounts by each of the 10 sponsors (9 companies plus Environmental Defense Fund). Nine of the sponsors provided equal amounts and the tenth (one of the companies) provided a small amount of supplemental funding due to additional logistical costs at one of their sampling sites. A second phase of the study is now underway, with funding of approximately $1.2 million. Nine of the original sponsors (EDF and eight of the original companies) and two additional sponsors (ConocoPhillips and Statoil) are currently supporting that work. Once again, funding is being provided in roughly equal amounts by all sponsors, in this case Environmental Defense Fund and the 10 company sponsors.

2. Is it correct that all of the data on methane emissions used in this study came from well sites operated by the nine natural gas companies – Anadarko, BG Group, Chevron, Encana, Pioneer, Shell, Southwestern Energy, Talisman Energy and XTO Energy – that provided "financial support, technical advice, and access to sites for sampling?"

Response: Yes, all of the sampling was done at sites operated by the companies that provided funding. The measurements that we report were made directly at the sources of the emissions. To make these measurements, the study team needed access to sites, and needed to safely install and operate measurement equipment that was often directly attached to production equipment. Participating companies provided access to production sites and equipment, and assisted in the design of safe sampling protocols, making these direct measurements of methane emissions possible.

3. Is it correct that all well sites visited and locations where the data were collected for use in the study came from a list of candidate sites provided by the following nine natural gas companies Anadarko, BG Group, Chevron, Encana, Pioneer, Shell, Southwestern Energy, Talisman Energy and XTO Energy?

Response: Yes, all of the sampling was done at sites identified by the companies. The procedures the study team used in selecting the sites are described in detail in the Supporting Information published by the Proceedings of the National Academy of Sciences. We have also summarized the procedures used in selecting sites in a "question and answer" document available on the web site summarizing the study. (http://dept.ceer.utexas.edu/methane/study/index.cfm) That summary follows:

"Methane emissions were measured directly at 190 natural gas production sites in the Gulf Coast, Midcontinent, Rocky Mountain and Appalachian production regions of the United States. The sites included 150 production sites with 489 wells. In addition to the 150 production sites, 27 well completion flowbacks, 9 well unloadings, and 4 well workovers were sampled; the sites were operated by 9 different companies. The types of sources that were targeted for measurement account for two thirds of methane emissions from all onshore and offshore natural gas production, as estimated in EPA's national greenhouse gas emission inventory. Of the nine companies that provided sites for sampling, at least three companies provided sites in each of the regions.

While the data presented in this work represents one of the most extensive datasets available on methane emissions from current natural gas production activities, the sites sampled still represent a small fraction of the total number of sites nationwide. Representative sampling was believed to be achieved by:

- Selecting a large number of participant companies
- Selecting a range of geographic areas to sample
- Setting minimum number of sampling targets in each area

The nine companies that participated in this study included mid-size and large companies. While there are thousands of oil and gas companies in the U.S., the participants do represent a sizable sample of overall U.S. production and well count. Participants account for almost 12% of all US gas wells, account for 16% of gross gas production, and almost half of the new well completions. Representativeness cannot be assured. The companies volunteered, and were not randomly selected.

Randomization in the selection of sites was achieved in a variety of ways, depending on the type of source. For completions, the study team provided time windows when the measurement team would be available in certain regions and host companies identified completions that would begin as soon as possible after the study team arrived. In most cases this scheduling completely determined which sites would be sampled. To illustrate this, consider that the total number of well completions, nationwide in 2011, for all the participating companies combined, averaged roughly 10 per day. That meant that in any given production region, on any particular day, just one or two new completions, for all of the companies combined, was likely to be starting.

The time commitment associated with sampling completions was extensive. Completions lasted up to two weeks; sampling equipment set up and tear down by the study team required a day before and a day after the completion. Unloading, workover and production site sampling was much shorter in duration, typically a few hours to a half day. Consequently, sites selected for unloading, workover and production site sampling were selected based on proximity to completion sampling. Typically, a list of candidate sites was provided by the host company. If the list was too long to be entirely sampled in the allotted time, the study team selected sites based on an ability to sample as many sites as possible in the time available..

One exception to this pattern was for Gulf Coast sites, where the study team, based in Austin, Texas, could make day trips to production sites. For these sites, the study team randomly selected from hundreds of potential sites provided by host companies. A second exception was for unloadings. These events were difficult to schedule since they were often done, by site operators, immediately as needed. This often did not allow the study team to travel to the site and set up equipment prior to the unloading occurring. Therefore, special efforts were made to identify and sample unloadings that could be scheduled."

4. The data used in the UT Study takes into account the upstream emissions from 489 gas wells and 27 hydraulic fracturing well completion flowback events or approximately - .1% of the total number of all the gas wells in the U.S. The Environmental Defense Fund's "FAQ About the University of Texas Methane Study" states, "While this study reflects only a portion of what is happening in the field in 2012, in absence of a statistically valid national survey, we are only able to use data we collected as the basis to assess the national implications of the results." (emphasis added). Do you agree with EF that the data collected in the UT Study does not allow for a "statistically valid national survey" that can serve as an actual national average for the level of methane emissions released from the remaining 99.9% of the nation's oil and gas wells?

Response: While the data presented in this work represents one of the most extensive datasets available on methane emissions from current natural gas production activities, as noted in your question, the sites sampled still represent a small fraction of the total number of sites nationwide. Representativeness cannot be assured. The companies volunteered, and were not randomly selected.

Nevertheless, the study team sought to make the data set as representative as possible by:

- Selecting a large number of participant companies
- Selecting a range of geographic areas to sample
- Setting minimum number of sampling targets in each area

The nine companies that participated in this study included mid-size and large companies. While there are thousands of oil and gas companies in the U.S., the participants do represent a sizable sample of overall U.S. production and well count. Participants account for almost 12% of all US gas wells, account for 16% of gross gas production, and almost half of the new well completions.

5. The UT Study found that 33% of the surveyed well completions at sites that were selected by the nine natural gas companies did not use reduced emission completions (REC) to control well flow back emissions. The Environmental Defense Fund's "FAQ About the University of Texas Methane Study" states that these non-REC wells "had low initial gas production compared to the controlled wells" and that "the wells with uncontrolled releases had much lower than average potential to emit." Given the industry selection of the sites and the lower emitting potential of these uncontrolled, non-REC wells, does the collected data allow for any type of rigorous conclusions about the current national level of REC utilization or the methane emission rates from uncontrolled well sites that were not surveyed as part of the study?

Response: The 27 well completion flowbacks samples in our study are the first direct measurements of emissions from completion flowbacks reported in the scientific literature; however, as noted in the response to the previous question, they represent a small fraction of the total number of well completions performed annually. While, as noted in our answer to the previous question, the study team sought to make the data as representative as possible, representativeness cannot be assured.

6. Several other peer reviewed studies have analyzed the methane emission rates associated with oil and gas drilling and found the emission rates to be significantly higher than emission rates derived from data collected in the UT Study. Does the UT Study invalidate the findings of the following two peer reviewed studies? If your answer is in the affirmative, please provide the published peer review literature other than the UT Study that supports such a conclusion.

   - Anna Karion, et al (2013) "Methane emissions estimate from airborne measurements over a western United States natural gas field," Geophysical Research Letters Volume 40, Issue 16, pages 4393-4397.
   - J. Peischl, et al, (2013) "Quantifying sources of methane using light alkanes in the Los Angeles basin, California," Journal of Geophysical Research: Atmospheres, Volume 118, Issue 10, pages 4974-4990.

Response: Our work does not invalidate the findings of the studies cited in the question. The studies cited in the question make an important contribution by using measurements of ambient methane concentrations to estimate total methane emissions to the atmosphere in the regions in which the measurements were made. The studies conclude that methane emissions are underestimated in current emission inventories, and the studies attribute this under-estimate, at least in part, to emissions from the natural gas supply chain.

The natural gas supply chain includes a variety of activities, including production, gathering, processing, transmission, distribution and use. Within the natural gas supply chain, some emission sources may be more important than others.

Our study looked at a subset of sources in natural gas production, which is in turn a subset of the natural gas supply chain. We found emissions from some sources (pneumatic controllers) were larger than anticipated from emission inventories and others (completion flowbacks), consistent with new regulations, were lower due to the presence of emission control equipment.

Both regional measurements and analyses, as reported in the studies cited in the question, and source specific studies, are needed to identify opportunities for emission reductions.

7. EPA's New Source Performance Standards for Oil and Gas Production do not currently contain requirements to control the emissions from many types of emissions control equipment used at oil and gas wells. Would the establishment of standards for pneumatic devices at wells, pressure relief valves at storage tanks, and compressors and pressurized motors used to move natural gas through processing plants and pipelines reduce VOC, methane and other emissions?

Response: Our study found that emissions from pneumatic controllers are larger than currently estimated. A similar conclusion was arrived at based on measurements made in British Columbia, released in December, 2013 (http://www.env.gov.bc.ca/cas/mitigation/ggrcta/reporting-regulation/pneumatics.html) When we estimated the national implications of our measurements of pneumatic controller emissions, we concluded that these emissions are one of the largest sources of methane emissions in the natural gas production sector. Whether the establishment of emissions standards for these devices would lower emissions would depend on the standard.

8. EPA's New Source Performance Standards for Oil and Gas Production do not contain requirements to control the completion and production emissions from wells that co-produce oil and natural gas. Do such co-produced wells release VOCs, methane and other emissions that can be controlled through reduced emission completions and other readily available technologies?

Response: Many of the sites at which we made measurements in our study produced both gas and hydrocarbon liquids. In our measurements of emissions from well completion flowbacks, for example, we found that reduced emissions completion equipment was effective at reducing emissions at sites that produced gas and sites that produced both gas and hydrocarbon liquids.

Questions from Senator Vitter

1. Dr. Allen did you or any of your research team have any trouble working with energy companies participating in the study? Did you or any of your research team have any problem gaining access to equipment or production facilities or anything else that would have hindered your work?

Response: The participating companies did not hinder our work. The companies were essential for the successful completion of the work. The participating companies provided access to sites and equipment, assisted in performing safety reviews of the sampling protocols, and provided technical insights and suggestions throughout the study. The participating companies have also all provided written assurances that they provided unrestricted access to their all of their sites to the study team.

2. In both the released study as well as in your testimony you mention that a majority of completion flowbacks sampled during the study, reduced emissions completions were being used and as a result, emissions were reduced by 99%. Is it safe to say that when EPA's rules are fully implemented next year and reduced emissions completions are even more widespread, the result will be an even more dramatic reduction in emissions from natural gas producers?

Response: As noted in the question, our measurements indicate that reduced emission completion (REC) equipment reduces methane emissions by 99%, as compared to uncontrolled venting of flowback fluids. We observed no instances in which the REC technology did not reduce emissions. Therefore, it is reasonable to conclude that if all completion flowbacks operate REC equipment, emissions will be reduced.

3. Why do you and your research team plan to continue studying pneumatic devices even though the study seems to make conclusions about their emissions?

Response: Our study, as well as a recently released study based on measurements made in Alberta and British Columbia, (http://www.env.gov.bc.ca/cas/mitigation/ggrcta/reporting-regulation/pneumatics.html) conclude that pneumatic controller emissions are higher than would be expected based on current emission estimation methods. Both studies also find that a relatively small fraction of the controllers have much higher emissions than the remainder of the controllers. This may be due to some controllers opening and closing valves more frequently than others, improper operation, or other factors. The sampling that our study team is doing now is aimed at understanding why some controllers emit more than others.

Senator WHITEHOUSE. Thank you very much, Dr. Allen. I appreciate it.

I am very pleased to welcome Mark Boling here. He has served as president of V+ Development Solutions, which is a division of Southwestern Energy Company since that division's creation in April 2012. Previously, he has been senior vice president, general counsel, and secretary of the board of directors to Southwestern and an executive vice president of Southwestern.

The mission of V+ Development is to identify and develop solutions for achieving balance among the economic, environmental, and social effects of Southwestern's activities, focusing in particular on the role of advancing the development of domestic natural gas supplies in achieving a low carbon energy future. He initiated and continues to lead Southwestern's efforts to collaborate with the Environmental Defense Fund and other environmental NGOs to develop a model regulatory framework for hydraulic fracturing operations.

Thank you, Mr. Boling, for being here. Please proceed.

STATEMENT OF MARK K. BOLING, PRESIDENT, V+ DEVELOPMENT SOLUTIONS, AND GENERAL COUNSEL, SOUTHWESTERN ENERGY COMPANY

Mr. BOLING. Good afternoon, Chairman Whitehouse, Ranking Member Inhofe, and Senator Vitter. My name is Mark Boling and I am General Counsel and President of V+ Development Solutions, a division of Southwestern Energy Company. Southwestern Energy Company is an independent exploration and production company and is the fifth largest producer of natural gas in the United States. I appreciate the opportunity to appear before you today and provide testimony regarding methane emissions from the Production Sector of Natural Gas Systems.

At Southwestern, we believe the development of America's natural gas resources is an important part of achieving a secure, low-carbon energy future for our country, but only if it is done right. The good news is that the solutions to doing it right are out there and if industry, environmental groups and regulators work together in a collaborative way, these solutions can be found and implemented.

One of the primary roles of our Development Solutions division is to engage the communities impacted by our operations, as well as other stakeholders, to assist us in maximizing the benefits while minimizing the negative impacts of our activities. We believe that by engaging in these problem-solving dialogs, it is possible to develop "smart regulations" for our industry. When I refer to "smart regulations," I am talking about rules that level the playing field for all companies and effectively manage risk by achieving the proper balance among the economic, environmental and social impacts of the regulated activities.

Southwestern believes that a good example of how collaboration between industry and regulators can lead to smart regulations is EPA's Natural Gas STAR Program. The Natural Gas STAR Program is a voluntary partnership that encourages oil and natural gas companies to adopt cost-effective technologies and practices that improve operational efficiency and reduce methane emissions.

Southwestern joined the Natural Gas STAR Program in 2005. Since our initial report in 2006, Southwestern has reported cumulative methane reductions of over 37 billion cubic feet of gas, primarily due to our use of Reduced Emission Completions, also known as Green Completions. Additionally, due to the hard work and innovation of our employees, Southwestern was able to drive down the incremental cost of conducting Reduced Emission Completions in our Fayetteville Shale project from approximately $20,000 per well to $0 per well, while at the same time capturing a significant amount of natural gas that would have otherwise been vented or flared.

The years of collaboration and innovation supported by the Natural Gas STAR Program provided key technological and operational practice information to support the recently enacted New Source Performance Standards, Quad O regulations. Southwestern believes the Quad O regulations are smart regulations as they effectively manage volatile organic compound, VOC, emissions from the production sector, and indirectly methane emissions, by requiring proven, cost-effective emission reduction technologies and practices. In fact, much of the equipment, controls and practices required by Quad O have already been implemented by Southwestern and many other companies that participate in the Natural Gas STAR Program.

Finally, I would like to say a few words about another important collaborative effort, the recently released upstream methane emissions study conducted by a team of researchers from the University of Texas and testing firms URS and Aerodyne Research. Since Dr. Allen has already provided details of the measurement data gathered from the study, I will limit my comments to the following key findings:

First, total estimated methane emissions from natural gas production were found to be comparable to the most recent EPA estimates.

Second, measured methane emissions from hydraulically fractured well completions were found to be significantly lower than the estimates used by EPA in the national emissions inventory.

And third, measured methane emissions from equipment leaks and certain types of pneumatic controllers were found to be higher than current EPA estimates.

This study shows that methane emissions from the natural gas production sector can be effectively minimized by applying reasonable emission capture and control practices. It also shows, however, that additional opportunities exist to reduce methane emissions from this sector.

Southwestern intends to actively pursue these opportunities by taking the following steps: implement an internal initiative to reduce methane emissions associated with our operations, including a leak detection and repair program; participate in additional studies to gather data on pneumatic controllers and liquids unloading events to increase the data set and improve knowledge; participate in a research and development project to identify or develop cost-effective methane emission monitoring devices; and work with other energy industry partners to develop a methane leadership initiative, with a primary goal of reducing methane emissions from the entire natural gas value chain.

Mr. Chairman, this concludes my testimony. I would be happy to answer any questions you may have.

[The prepared statement of Mr. Boling follows:]

Testimony

Before the
United States Senate
Committee on Environment and Public Works, Subcommittee on Oversight

On

Methane Emissions from the Production Sector of Natural Gas Systems

Mark K. Boling
President, V+ Development Solutions and General Counsel
Southwestern Energy Company

November 5, 2013

Good afternoon Chairman Whitehouse, Ranking Member Inhofe and other members of the Subcommittee. My name is Mark Boling and I am General Counsel and President of the V+ Development Solutions division of Southwestern Energy Company. Southwestern Energy Company is an independent exploration and production company, and is the fifth (5th) largest producer of natural gas in the United States. I appreciate the opportunity to appear before you today and provide testimony regarding methane emissions from the Production Sector of Natural Gas Systems.

At Southwestern, we believe the development of America's natural gas resources is an important part of achieving a secure, low-carbon energy future for our country, but only if it is done right. The good news is that the solutions to "doing it right" are out there and if industry, environmental groups and regulators work together in a collaborative way, these solutions can be found and implemented.

One of the primary roles of our V+ Development Solutions division is to engage the communities impacted by our operations, as well as other stakeholders, to assist us in maximizing the benefits while minimizing the negative impacts of our activities. We believe that by engaging in these "problem solving" dialogues, it is possible to develop "smart regulations" for our industry. When I refer to "smart regulations", I am talking about rules that level the playing field for all companies and effectively manage risk by achieving the proper balance among the economic, environmental and social impacts of the regulated activities.

Southwestern believes that a good example of how collaboration between industry and regulators can lead to smart regulations is EPA's Natural Gas Star Program. The Natural Gas Star Program is a voluntary partnership that encourages oil and natural gas companies to adopt cost-effective technologies and practices that improve operational efficiency and reduce methane emissions.

Southwestern joined the Natural Gas Star Program in 2005. Since our initial report in 2006, Southwestern has reported cumulative methane reductions of over 37 Bcf (Billion Cubic Feet), primarily due to our use of Reduced Emission Completions (also known as "Green Completions"). Additionally, due to the hard work and innovation of our employees, Southwestern was able to drive down the incremental cost of conducting Reduced Emission Completions in our Fayetteville Shale project from approximately <u>$20,000 per well</u> to <u>$0 per well</u>, while at the same time capturing a significant amount of natural gas that would have otherwise been vented or flared.

The years of collaboration and innovation supported by the Natural Gas Star Program provided key technological and operational practice information to support the recently enacted NSPS, "Quad O" regulations. Southwestern believes that the "Quad O" regulations are "smart regulations" as they effectively manage VOC (Volatile Organic Compound) emissions (and indirectly methane emissions) from the production sector by requiring proven, cost-effective technologies and practices to reduce VOC emissions. In fact, much of the equipment, controls and practices required by "Quad O" have already been implemented by Southwestern and many other companies that participate in the Natural Gas Star Program.

Finally, I would like to say a few words about another important collaborative effort, the recently released upstream methane emissions study conducted by a team of researchers from the University of Texas and testing firms URS and Aerodyne Research. Since Dr. Allen is providing the Subcommittee with the details of the measurement data gathered from the study, I will limit my comments to the following key findings:

- Total estimated methane emissions from natural gas production were found to be comparable to the most recent EPA estimates;

- Measured methane emissions from hydraulically fractured well completions were found to be significantly lower than the estimates used by the EPA in the national emissions inventory; and

- Measured methane emissions from equipment leaks and certain types of pneumatic controllers were found to be higher than current EPA estimates.

This study shows that the amount of methane emissions from the natural gas production sector can be effectively minimized by applying reasonable emission capture and control practices. It also shows, however, that additional opportunities exist to reduce methane emissions from this sector. Southwestern intends to actively pursue these opportunities by taking the following steps:

- Implement an internal initiative to reduce methane emissions associated with our operations, including a leak detection and repair program;

- Participate in additional studies to gather data on pneumatic controllers and liquids unloading events to increase the data set and improve knowledge;

- Participate in a research and development project to identify or develop cost effective methane emission monitoring devices; and

- Work with other energy industry partners to develop a methane leadership initiative, with a primary goal of reducing methane emissions from the entire natural gas value chain.

Mr. Chairman, this concludes my testimony. I would be happy to answer any questions you may have.

swn
Southwestern Energy®

Corporate Office
2350 N Sam Houston Pkwy E
Suite 125
Houston, Texas 77032
Tel: 281 618 4806
Fax: 281 618 4620
mboling@swn.com

Mark K. Boling
President
V+ Development Solutions

January 13, 2014

Senate Committee on Environment
and Public Works
410 Dirksen Senate Office Building
Washington, DC 20510

Attention: Mara Stark-Alcalá

Re: Fugitive Methane Emissions from Oil & Gas Operations

Dear Senators Boxer and Vitter:

Set forth below are my answers to the follow-up questions posed in your December 20, 2013 letter concerning fugitive methane emissions from oil and gas operations.

Questions from Senator Boxer

Question 1: EPA's New Source Performance Standards for Oil and Gas Production do not currently contain requirements to control the emissions from many types of emissions control equipment used at oil and gas wells. Would the establishment of standards for pneumatic devices at wells, pressure relief valves at storage tanks, and the compressors and pressurized motors used to move natural gas through processing plants and pipelines reduce VOC, methane and other emissions?

Answer: Yes. The Environmental Protection Agency's (EPA's) recent enactment of Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution at 40 C.F.R. Part 60, Subpart 0000 ("NSPS 0000") should result in significant reductions in emissions of volatile organic compounds (VOC's) and, indirectly, methane emissions from the oil and gas production sector. The NSPS 0000 regulations currently regulate emissions from (i) continuous bleed natural gas-driven pneumatic controllers at well locations with a bleed rate greater than 6 standard cubic feet per hour (scfh), (ii) continuous bleed natural gas-driven pneumatic controllers at natural gas processing plants (regardless of bleed rate), (iii) storage tanks that have the potential to emit VOC's equal to or greater than 6 tons per year (tpy), (iv) centrifugal compressors (with wet seals) and reciprocating compressors at gathering/boosting stations and gas processing plants, and (v) equipment leaks at natural gas processing plants.

There are additional pieces of equipment utilized at well locations and compressor facilities that are not covered by the NSPS 0000 regulations and have the potential for fugitive emissions from leaking components. An example of the type of components that are most likely to leak are thief hatches and pressure relief valves on storage tanks, and valves, flanges, connectors and open-ended lines that contain or contact a process stream with hydrocarbons.

A potentially cost-effective method for reducing emissions from these types of components is to implement a leak detection and repair program (LDAR program) at well locations and compressor facilities. The purpose of the LDAR program is to identify fugitive emissions and timely repair the leaking components through the periodic inspection of the equipment located at the well location and compressor facilities. In its recently proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, the State of Colorado is proposing that operators of well production facilities, storage tanks and compressor stations implement an LDAR program to minimize fugitive emissions from leaking components.

Question 2: EPA's New Source Performance Standards for Oil and Gas Production do not contain requirements to control the completion and production emissions from wells that co-produce oil and natural gas. Do such co-produced wells release VOCs, methane and other emissions that can be controlled through reduced emission completions and other readily available technologies?

Answer: Yes. Wells that co-produce oil and natural gas release VOC's, methane and other emissions that could be controlled through reduced emission completions (RECs) and other readily available technologies. However, much like the "cost-benefit analysis" that is utilized to assess the viability of installing vapor recovery units on crude oil storage tanks, one would need to consider both the productive capacity of the co-produced well and the gas-oil ratio of the oil produced from the co-produced well to determine what threshold production characteristics would be required to make an REC on a co-produced well cost effective.

Questions from Senator Vitter

Question 1: Mr. Boling, does Southwestern Energy believe EPA used the Natural Gas Star data appropriately when they revised their completions emission factor? Was any of this information misused?

Answer: For the reasons set forth below, Southwestern Energy does not believe EPA "misused" the information from the Natural Gas Star program when they revised their completions emission factor.

In assessing EPA's use of the Natural Gas Star data in estimating emissions from hydraulically fractured well completions, it is important to distinguish between "potential emissions" and "net emissions." The term "potential emissions" refers to the amount of methane that would be emitted if all of the methane leaving the wellhead during the flowback was vented to the atmosphere. The "net emissions" from the well completion event are equal to the potential

emissions less (i) methane captured or controlled due to regulatory requirements and (ii) voluntary emission reductions.

Estimating potential emissions from hydraulically fractured well completions is difficult because the production characteristics and flowback period for each well can vary significantly. These variations can be due to the type of reservoir being completed (i.e. some reservoirs are not negatively impacted by partial flowback and can have shorter flowback periods) and the type of completion being deployed (i.e. reduced emission completion or venting/flaring). For example, in the recently completed methane emission study conducted by the University of Texas and testing firms URS and Aerodyne Research, the flowback periods for the well completions measured ranged between 5 hours and 14 days. For Southwestern Energy's hydraulically fractured well completions in the Fayetteville Shale, the flowback periods have ranged between 30 hours and 14.8 days.

EPA used data provided by industry under the Natural Gas Star program to estimate potential emissions from hydraulically fractured well completions. Based on the data provided, EPA assumed a flowback period of between 3 and 10 days, and estimated an average emission rate of 9,175 mcf (thousand cubic feet) per completion event. For comparison purposes only (since potential emission numbers vary considerably from basin to basin), Southwestern Energy calculated the average potential emissions from its hydraulically fractured well completions in the Fayetteville Shale to be approximately 16,000 mcf per completion event when REC technology was originally evaluated.

To estimate net emissions from hydraulically fractured well completions, one must determine the average amount of methane captured or controlled during the completion due to regulatory requirements and/or voluntary reductions and subtract this amount from the potential emissions for the well completion. For the most part, this means identifying the percentage of hydraulically fractured well completions that utilize REC technology (the "REC Percentage"). Until recently, well operators were not required to report to EPA whether or not REC technology was utilized in their hydraulically fractured well completions. Therefore, EPA had to calculate the REC Percentage from the best data available, and estimated that approximately 15% of all hydraulically fractured well completions utilize REC technology. In comments filed by America's Natural Gas Alliance (ANGA) to the proposed NSPS 0000 regulations, ANGA stated that, based on a survey of its member companies, it estimated that as much as 93% of hydraulically fractured well completions use REC technology.[1] Other comments filed by the American Petroleum Institute (API) indicated that, based on API's estimate of available REC equipment, approximately 20% of all hydraulically fractured well completions utilize REC technology.[2] However, based on the recently released 2012 greenhouse gas data for Petroleum and Natural Gas Systems collected under EPA's Greenhouse Gas Reporting Program, industry reported that out of a total of 9,466 hydraulically fractured gas well completions, REC technology was utilized in 5,059 (i.e. industry reported an REC Percentage of 53%).

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[1] ANGA comments to EPA on Docket ID No. EPA-HQ-OAR-2010-0505.
[2] API comments to EPA on Docket ID No. EPA-HQ-OAR-2010-0505.

As one can see from both the broad range of estimates for the REC Percentage (EPA – 15%; API – 20%; ANGA – 93%), and the first reported REC Percentage under the Greenhouse Gas Reporting Program (53%), the EPA's low estimate for the REC Percentage can be attributed to the inherent difficulty in making such an estimate and not to any "misuse" of data.

Question 2: In your testimony you mentioned that in your V+ development solutions division you work to engage in communities around your operations in an effort to develop "smart regulations." Given the different geologies and circumstances industry faces across the country, aren't many of these "smart regulations" better developed at the state level closer to the communities you are attempting to work with?

Answer: **As stated in my written testimony, when I refer to "smart regulations," I am talking about rules that effectively manage risk by achieving the proper balance among the economic, environmental and social impacts of the regulated activities. To effectively manage risk in the regulatory context, the regulating authority must first identify all of the risks associated with the regulated activity. Once these risks are identified, the regulating entity must then accurately assess both the probability of the risk occurring and the potential impact of the risk if it does occur. To determine what level of government (federal, state or local) is best suited to make these assessments, one must analyze a number of factors, including (i) does the regulating authority require any special knowledge or expertise concerning regional or local conditions in order to effectively regulate the activity, (ii) are the potential impacts of the regulated activity local, regional or multi-state, (iii) are the risks associated with the regulated activity the same from state-to-state, and (iv) are the proposed solutions for effectively managing these risks the same from state-to-state.**

This analysis is necessarily "risk specific", and the answer as to what level of government is in the best position to effectively manage the risk will vary. For example, applying these factors to the regulation of subsurface risks associated with drilling, completing and producing hydraulically fractured wells, one concludes that due to the vastly different geological, hydrological, topographical and other conditions encountered within each hydrocarbon basin across the country, the states are in the best position to regulate these activities. However, if you apply these same factors to the regulation of air emissions associated with the drilling, completion and production of a hydraulically fractured well, one can conclude that while the solutions to many of the "air emission risks" are the same from state-to-state, the potential for regional differences in both air quality (i.e. attainment vs. nonattainment status) and available mitigation strategies, makes the current framework of "cooperative federalism," as set out in the Clean Air Act, the best way to regulate air emissions.

Question 3: You stated that Southwestern was able to drive down the cost of green completions in your Fayetteville Shale project from $20,000 per well to $0. Do those economics include all the gas captured with your green completion equipment or just the gas that would otherwise be emitted if green completions weren't performed?

<u>Answer</u>: Initially, the incremental capital cost of conducting a reduced emission completion (REC) in our Fayetteville Shale project was approximately $20,000 per well. This cost was based on utilizing nitrogen lift and certain rental equipment (e.g. separator, choke manifold, sand trap and debris catcher) to perform the REC. Southwestern has been able to drive down this incremental cost to $0 per well by switching from nitrogen lift to gas lift and by redesigning the production separator to handle larger gas/fluid volumes. In addition, due to the level of activity in our Fayetteville Shale project, Southwestern has been able to purchase most of the REC equipment we need at an overall cost that is less than the cost of renting REC equipment and then later installing permanent production equipment.

Our ability to get the incremental cost of performing REC's down to $0 per well has nothing to do with the revenues we generate from selling the natural gas that would have been vented or flared without the REC. As described above, when REC technology was originally evaluated by Southwestern, we estimated that the average potential emissions (i.e. without utilizing REC) from a hydraulically fractured well completion in the Fayetteville Shale was 16,000 Mcf (thousand cubic feet) per well. At a natural gas price of $4.00 per Mcf, Southwestern would receive additional gross revenues of $64,000.00 from the captured emissions.

<u>Questions 4</u>: In your testimony you also mention that Southwestern intends to "participate in additional studies," "gather data", and participate in "research and development." Would you agree that further methane regulations are not currently necessary nor justified given that EPA's NSPS has yet to be fully implemented and additional study and research is ongoing?

<u>Answer</u>: I believe the NSPS 0000 regulations are "smart regulations" and should be fully implemented. The question whether "further methane regulations" are necessary or justified prior to the implementation of the NSPS 0000 regulations is a difficult one to answer. An argument can be made that industry should be allowed to "absorb" the new NSPS 0000 regulations and let regulators gauge their impact on VOC emissions (and indirectly, methane emissions) before new regulations are imposed. One could also argue that combining the new NSPS 0000 regulations with appropriate incentives for industry to voluntarily reduce emissions even further could result in more rapid emission reductions than trying to move additional regulations through the regulatory process.

However, as evidenced by the State of Colorado's recently proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, there are members of the regulatory community, the environmental community and industry that believe the NSPS 0000 regulations can and should be modified or supplemented in a way that will "significantly reduce emissions of VOC's and other hydrocarbons from oil and natural gas development".[3] Since the NSPS 0000 regulations will not be fully implemented until 2015, and the impact on emissions will not be known until 2016-2017 (at the earliest), now may be the right time to assess whether the NSPS

[3] Prehearing Statement of Noble Energy, Inc. and Anadarko Petroleum Corporation dated January 6, 2014, before the Air Quality Control Commission, State of Colorado, In the Matter of Proposed Revisions to Regulation Number 3, Parts A, B and C, Regulation Number 6, Part A and Regulation Number 7.

Senate Committee on Environment and Public Works
January 13, 2014
Page 6

0000 regulations effectively manage the risks associated with VOC emissions from the oil and gas production sector.

It was my pleasure to provide testimony to the Senate Committee on Environment and Public Works on the very important issue of fugitive methane emissions from oil and gas operations. Please feel free to contact me if you have any further questions.

Very truly yours,

Mark K. Boling

MKB:pt

Senator WHITEHOUSE. Thank you, Mr. Boling, I appreciate it.

Our next witness is Dr. Vignesh Gowrishankar, who is a staff scientist in sustainable energy at the Natural Resources Defense Council. His work focuses on Federal and State policies, programs, and mechanisms to clean up natural gas production, help deploy cleaner resources across the electric grid, and promote greater industrial energy efficiency.

Prior to joining NRDC, Dr. Gowrishankar served as a senior policy advisor on climate change adaptation and mitigation issues to the premier of the Australian state of Victoria and served as a management consultant with McKinsey & Company in a variety of industries. He earned his Ph.D. from Stanford University and his undergraduate degree at the Indian Institute of Technology Madras in Tamil Nadu, India. We are delighted to have him here.

Please proceed, Dr. Gowrishankar.

STATEMENT OF VIGNESH GOWRISHANKAR, Ph.D., STAFF SCIENTIST, SUSTAINABLE ENERGY, NATURAL RESOURCES DEFENSE COUNCIL

Mr. GOWRISHANKAR. Thank you, Chairman Whitehouse, Ranking Member Inhofe, and Senator Vitter. Thank you for the opportunity to testify here today. My message today is simple: The Federal Government needs to do more to limit the release of methane and other pollutants from the production and distribution of natural gas. Absent such steps, the increased use of natural gas will aggravate smog, expose the public to more carcinogenic chemicals, and worsen climate change.

The good news is that the technologies to reduce the release of these pollutants exist today and the oil and gas industry can actually make more money using them. Failure to employ these health and environment protecting technologies is a classic market failure.

The leakage and sometimes intentional venting of gas occurs across the supply chain, from the production to transport. This releases harmful and toxic pollutants and methane, a highly potent greenhouse gas that accelerates and magnifies climate change. This is the right time to be discussing the topic of methane leakage, 1 year after Hurricane Sandy and close on the heels of the President's Climate Action Plan.

According to the latest EPA data, methane leakage equals about 1.5 percent of all natural gas produced each year, and recent peer review literature has reported leakage as high as 7 percent, or even more, in certain locations. To put that in perspective, at just 3 percent leakage, natural gas is no better than coal in terms of its contribution to near-term climate change. Continuing research on the precise level of leakage should not obscure the fundamental and incontrovertible point that natural gas is leaking into the atmosphere, wasting fuel, polluting the air, and damaging our climate; when, instead, that fuel could economically be put to use.

The technologies to control emissions are not hard to understand at a basic level. They include such common sense steps as capturing the big release of gas that occurs when a well is fracked, using better seals for compressors and making sure they are properly maintained and functioning, ensuring that wells that control gas don't actually leak the gas, putting a sealed lid on storage tanks so that gas does not escape, and using detectors to identify when and where equipment is leaking. And there are many others. This equipment has been tried and tested, and is being manufactured and sold. A number of leading companies are using them in some of their operations and Dr. Allen's study further proves that they can be very effective.

These technologies enable industry to capture and therefore sell the gas that is now leaking into the atmosphere. As a result, these technologies pay for themselves in short time, typically in just a few months to about 2 to 3 years. NRDC has identified 10 such technologies that are especially cost-effective. Employing these 10 technologies could potentially reduce 60 to 80 percent of methane leakage, and possibly even more. Yet, using these proven, cost-effective technologies is not yet industry standard practice. This is a classic market failure. Industry is leaving money on the table and the public is paying the price for suffering the health and environmental harms of leakage.

The EPA recently established standards that begin to cut this wasteful leakage, but these standards are too weak and will cut less than one-sixth of total emissions in the near term. EPA has the authority and obligation under current law to do more. EPA should be setting stronger standards that target methane directly and require emission controls for new and existing equipment already in the field; all types of wells, including oil wells that co-produce gas, such as those in North Dakota; all significant emission sources across the entire oil and gas supply chain. Such additional standards could actually benefit the entire economy and help royalty owners, U.S. equipment manufacturers and service providers, and well trained technicians, operators, and pipe fitters.

Ultimately, the solution to climate change is moving away from fossil fuels entirely and relying on energy efficiency, renewables, and zero emission energy sources. Deploying these should be the primary goal of U.S. energy policy. But until then we need to ensure that the fossil fuels we do use have the lowest environmental footprint possible, and reducing leakage and venting of methane is one of the easiest things we can take in this regard. There is absolutely no excuse to delay action.

Thank you again. I would be happy to take any questions.

[The prepared statement of Mr. Gowrishankar follows:]

TESTIMONY OF VIGNESH GOWRISHANKAR, Ph.D.,
STAFF SCIENTIST, NATURAL RESOURCES DEFENSE COUNCIL
HEARING ON
"FUGITIVE METHANE EMISSIONS FROM OIL AND GAS OPERATIONS"
BEFORE THE COMMITTEE ON ENVIRONMENT & PUBLIC WORKS
SUBCOMMITTEE ON OVERSIGHT
U.S. SENATE
NOVEMBER 5, 2013

Thank you, Mr. Chairman for the opportunity to testify today. My name is Vignesh Gowrishankar and I am a Staff Scientist at the Natural Resources Defense Council (NRDC). My work focuses on sustainable energy issues including examining technologies and practices for reducing pollution from oil and gas production, helping to deploy cleaner resources on the electric grid, and promoting greater industrial energy efficiency.

NRDC is a nonprofit organization with more than 350 scientists, lawyers and environmental specialists dedicated to protecting the environment and public health in the United States and internationally, with offices in New York, Washington D.C., Montana, Los Angeles, San Francisco, Chicago, and Beijing. Founded in 1970, NRDC uses law, science and the support of 1.3 million members and online activists to protect the planet's wildlife and natural environment, and to ensure a safe, healthy environment for all living things. NRDC's top institutional priority is curbing global warming and building the clean energy future.

I. INTRODUCTION

We all know that a boom in oil and gas production, using a technique called hydraulic fracturing (or fracking) is changing our nation's energy profile. We must minimize the environmental and public health impacts of this form of fossil fuel production, protect communities that may be affected by it and make sure that the domestic oil and gas boom does not distract us from or prevent investment in crucial clean energy strategies, which represent the best path forward. To solve the climate crisis we need to boost energy efficiency and transition to renewable, zero-emission sources of energy as quickly as possible. President Obama's Climate Action Plan[1] reaffirms the Administration's commitment to reducing emissions, by achieving 17 percent emissions reductions (below 2005 levels) by 2020. Eventually we need to go beyond that and rely on renewable and zero-emissions energy sources, and efficient energy use. Still, today the United States relies

[1] Executive Office of the President, The President's Climate Action Plan, June 2013, available at www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.

predominantly on fossil fuels and will for some time, so it is crucial to reduce the environmental and public health impacts of all forms of fossil fuel production.

My testimony focuses on the problem of methane emissions from the oil and gas sector, which take place today at high volumes when natural gas is accidentally leaked or intentionally vented into the air. In both cases, natural gas goes to waste unnecessarily. And as I discuss below, these natural gas releases pose an environmental and public health problem for several important reasons. Natural gas contains a number of harmful pollutants such as volatile organic compounds that cause ground-level smog and hazardous air pollutants that are toxic, all of which can affect public health. And the chief component of natural gas is methane, which is a highly potent greenhouse gas, contributing to climate change. My testimony focuses on the need for the federal government to establish strong standards that will require the oil and gas industry to use available, tried and tested, and cost-effective technologies to reduce methane leakage. Such standards will protect the air we breathe, reduce greenhouse gas emissions and prevent the waste of a valuable energy commodity.

When natural gas is burned at a power plant to generate electricity, for example, it emits far less carbon pollution than coal-based electricity.[2] However, if methane leaks into the atmosphere during the *production and transport* of natural gas before it reaches the power plant (or other points of use), then the relative greenhouse gas benefit of natural gas versus other fossil fuels is diminished (or even potentially eliminated depending on the actual methane leakage levels versus the alternative fossil fuel and use, and the time horizon, in question).

For instance, natural gas provides a clear advantage over coal-fired electricity from a greenhouse gas perspective only when the methane leakage rate as a fraction of total production is below 3 percent. If leakage rates are between 3 percent and around 7-8 percent, natural gas loses its advantage over coal in the near-term (because methane's global warming potency is very high over shorter periods such as 20 years). If emissions exceed 7-8 percent, natural gas has no advantage over coal even over the long-term.[3]

The numbers above are for electricity generation from natural gas or coal. But when using these fuels directly to generate heat (as opposed to electricity, as in

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[2] EPA, Clean Energy- Air Emissions, available at http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html.
[3] Alvarez, R. et al., Greater focus needed on methane leakage from natural gas infrastructure, published in Proceedings of the National Academy of Sciences, 2012, available at http://www.pnas.org/content/early/2012/04/02/1202407109.abstract.

industrial facilities), natural gas squanders its advantage over coal from a greenhouse gas perspective at even lower methane leakage levels. Likewise, the leakage levels needed to ensure a greenhouse gas advantage are also lower for other uses of natural gas versus alternative fuels – for instance leakage must be less than 1 percent when comparing with diesel use in heavy-duty vehicles.

As I describe later in my testimony, the methane leakage rate from the oil and gas industry is significant, although there are some uncertainties. The latest estimates indicate that about 8.4 million metric tons of methane are lost annually in leaks to the atmosphere, or approximately 1.5 percent of annual natural gas production. These emissions are equivalent to annual greenhouse gas emissions from 35 million passenger vehicles or 50 coal-fired power plants.[4] What we do know for sure is that only by curtailing methane emissions can the greenhouse gas advantage of natural gas relative to coal and other fossil fuels be maximized.

[4] EPA, Greenhouse Gas Equivalencies Calculator, available at http://www.epa.gov/cleanenergy/energy-resources/calculator.html.

II. SUMMARY OF TESTIMONY

My testimony will elaborate on the following key messages. A considerable amount of methane, along with other harmful air pollutants, is currently being leaked and vented from the oil and gas industry. Emissions control technologies and associated practices to significantly limit such pollution exist today, have been tried and tested, and are being used by some oil and gas producers in the field already. These are also commercially cost-effective and profitable, and can generate value for the broader economy.[5] But voluntary implementation of these profitable measures has not occurred comprehensively across the industry to satisfactorily limit emissions. Hence, there is a strong justification to fix these market failures, and establish emission control standards that will help to ensure environmental and community safety, while generating economic value. The recently-established EPA New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants for the oil and gas industry[6] are

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[5] Susan Harvey, Vignesh Gowrishankar and Thomas Singer, Leaking Profits: The U.S. Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste, published by NRDC, April 2012, available at http://www.nrdc.org/energy/leaking-profits.asp.

[6] EPA, 40 CFR Parts 60 and 63, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews: Final Rule, Federal Register, Vol. 77, No. 159, August 16, 2012, Page 49490-49600.

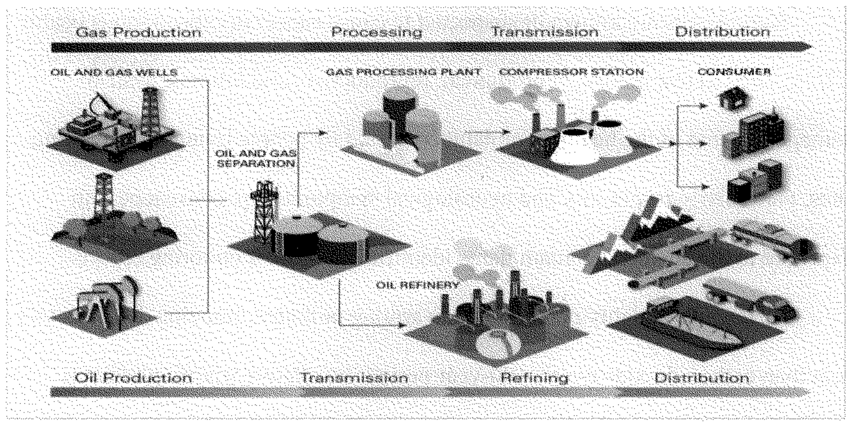
an important first step in the right direction. The recent study led by researchers from the University of Texas confirms that industry emissions are significant, but that such standards do work and can be very effective at reducing these emissions. However, other emission control standards can be much improved and the federal government should take the lead in establishing such standards.

Specifically, the Environmental Protection Agency (EPA) has both the authority and the responsibility to establish standards to reduce methane pollution from the oil and gas industry. This includes establishing standards that specifically target methane emissions and cover (i) existing equipment, in addition to new and modified ones; (ii) all types of wells from which natural gas can be produced; and (iii) all sources of methane emissions across the entire natural gas supply chain. In my testimony I recommend specific actions that can be taken by the EPA in this regard, in collaboration with other agencies and the oil and gas industry. These actions fit very well with President Obama's Climate Action Plan, which calls for developing an interagency methane strategy that coordinates government action to analyze emissions data, and identify, improve and implement best practices to reduce methane emissions, in collaboration with other sectors of the economy.

III. NATURAL GAS EMISSIONS, WASTE AND LEAKAGE CAUSE HARMFUL POLLUTION AND LOST ECONOMIC VALUE

Natural gas consists mostly of methane; as much as 90 percent can be methane. Natural gas also contains volatile organic compounds (VOCs), and hazardous air pollutants (HAPs) such as benzene, toluene, ethylbenzene and xylene among others. The proportions of these components in any particular natural gas stream depend on a number of factors, such as the type of geological resource from which it came.

Natural gas can be emitted from various equipment and processes in the supply chain, especially when appropriate emission controls are not in place. It is sometimes intentionally vented, for instance when cleaning out wells or repairing pipeline leaks; this causes preventable waste. Leaks can also occur from aging, improperly functioning or outdated equipment. For these reasons, natural gas leaks can occur from wells in the extraction and production portion of the supply chain, from processing equipment while compressing, drying or cleaning the gas, and from various components during storage, long-distance transportation and local distribution of gas to residential, commercial and industrial customers. A simplified schematic below depicts the natural gas supply chain.



When natural gas is emitted into the atmosphere all of its components have harmful effects. VOCs have been shown to play a significant role in creating unhealthy air, most notably due to their contribution to the formation of ground-level ozone or "smog," a powerful respiratory toxicant known to aggravate asthma and other respiratory conditions.[7] Several recent studies have identified pollution from oil and gas facilities, some where fracking is being deployed, as contributing to regional ozone problems in Colorado, Texas, and Pennsylvania.[8,9,10,11]

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[7] EPA. An Introduction to Indoor Air Quality – Volatile Organic Compounds – Health Effects, available at http://www.epa.gov/iaq/voc.html#Health_Effects.
[8] Pétron G, Frost G Miller BR, Hirsch AI, Montzka SA, Karion A., Trainer M, Sweeney C, Andrews AE, Miller L, Kofler J, Bar Ilan A, Dlugokencky EJ, Patrick L, Moore CF, Ryerson TB, Siso C, Kolodzey, W, Lang PM, Conway, T, Novelli P, Masarie K,

Some HAPs are known or suspected to cause cancer or other serious health effects, such as respiratory, neurological, reproductive, and immune system damage.[12] Some of the health complaints reported by people living near fracking sites, particularly respiratory and neurological symptoms, are consistent with exposure to the chemical contaminants identified in some monitoring reports.[13]

Methane is a highly potent global warming pollutant, trapping 34 times more heat than carbon dioxide over a 100-year period. Its relative warming effect is almost three times greater (86) when a 20-year timeframe is considered.[14] As a result, methane leaked into the atmosphere can accelerate and magnify global warming and climate change.

Much of the HAPs and VOCs are removed from the natural gas stream in gas processing plants. As such, the transportation and distribution portions of the

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Hall B, Guenther D, Kitzis, D, Miller J, Welsh, D, Wolfe D, Neff W, Tans P., Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study, Journal of Geophysical Research Volume 117, 2012.

[9] Gilman JB, Lerner BM, Kuster WC,de Gouw J, Source signature of volatile organic compounds (VOCs) from oil and natural gas operations in northeastern Colorado, Environ Sci Technology, 2013, DOI: 10.1021/es304119a.

[10] Litovitz A, Curtright A, Abramzon S, Burger N. Samaras C, Estimation of regional air-quality damages from Marcellus Shale natural gas extraction in Pennsylvania. Environ. Res. Lett. 8, 2013.

[11] Olaguer E, The potential near-source ozone impacts of upstream oil and gas industry emissions. Journal of Air and Waste Management. 62:8, 966-977, 2012.

[12] EPA, Toxic Air Pollutants – About Air Toxics, available at http://www.epa.gov/air/toxicair/newtoxics.html

[13] McKenzie Witter RZ, Newman LS, Adgate JL. 2012. Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources. Sci Total Environ. 2012 May 1;424:79-87.

[14] Intergovernmental Panel on Climate Change (IPCC), Working Group I Contribution to the IPCC Fifth Assessment Report (AR5), Climate Change 2013: The Physical Science Basis, 2013, available at http://www.climatechange2013.org/images/uploads/WGIAR5_WGI-12Doc2b_FinalDraft_Chapter08.pdf.

supply chain further downstream emit less VOCs and HAPs, relative to methane, though large leaks of processed gas can still emit significant VOCs and HAPs (in addition to the methane).

Clearly, preventing natural gas leakage will reduce these significant environmental effects. It will also curb the preventable waste of a natural resource. But that's not all. It will also generate additional profit for industry, and revenue for taxpayers and royalty owners[15]. And as the benefits from doing so outweigh the cost, industry can easily afford to adopt the necessary technologies.

My testimony is derived in large part from an NRDC report published in March 2012, titled *"Leaking Profits: The U.S. Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste"* (henceforth referred to simply as *Leaking Profits*). I was the co-author of the report. The principal author was Susan Harvey, of Harvey Consulting, LLC. Ms. Harvey has more than 25 years of experience as a Petroleum and Environmental Engineer, working on oil and gas exploration and development projects. As such,

[15] U.S. Government Accountability Office (GAO), Opportunities Exist to Capture Vented and Flared Natural Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases, October 2010, available at http://www.gao.gov/new.items/d1134.pdf. The report found that industry could reduce venting and flaring onshore by at least 40 percent, which would represent $23 million in additional royalty payments to the federal government annually (and reduce greenhouse gas emissions by an amount equivalent to about 16.5 million metric tons of CO_2—the annual emissions equivalent of 3.1 million cars).

both the report and my testimony draw on a wealth of experience in the oil and gas industry. I would like to enter that report into the record.

The central conclusions of *Leaking Profits* were as follows:

- Leaking natural gas causes harmful pollution and symbolizes unnecessary waste of a valuable resource;
- Ten technically feasible and commercially viable technologies are available today that can substantially limit this leakage;
- If these ten technologies could be implemented throughout the industry, they would have the potential to address and reduce more than 80 percent of EPA's estimated emissions, and rein in methane emissions to under half a percent of total production;
- The technologies all pay for themselves within a very short timeframe, and can generate additional revenue and profit to industry;
- While voluntary actions have been somewhat helpful in reducing emissions, enhanced standards are necessary to achieve our climate needs and goals.

Despite ongoing refinements to the emissions estimates, the central messages of *Leaking Profits* remain true today.

IV. LEAKAGE OF METHANE (ALONG WITH OTHER POLLUTANTS) FROM THE OIL AND GAS INDUSTRY IS CONSIDERABLE, THOUGH THERE ARE UNCERTAINTIES

In 2011, the oil and gas industry produced approximately 28,000 billion cubic feet (bcf) of natural gas.[16] According to the latest greenhouse gas inventory published by the EPA in April 2013,[17] the industry leaked or vented approximately 435 bcf (approximately 8.4 million metric tons) of methane. This translates to a methane loss rate of approximately 1.5 percent of gross production. (The loss rate estimated in *Leaking Profits* was 2.4 percent, based on data published in 2011. EPA emissions data has been updated over the last two years.[18])

While the EPA data are the most recent, the question of how much natural gas is leaked or vented is still uncertain. More comprehensive data is becoming available. Separate from the EPA greenhouse gas inventory, the oil and gas industry is required to submit emissions information pursuant to the Greenhouse

[16] U.S. Energy Information Administration (EIA), Natural Gas Withdrawals and Production, accessed November 2013, available at http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm.
[17] EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2011, April 2013, Table ES-2, available at http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.
[18] This has primarily been due to large downward changes in estimated emissions from liquids unloading (well clean-ups), and changes to estimated emissions during the fracturing and refracturing of wells. However, we note that research of methane emissions is ongoing, and recent studies such as the one led by Dr. David Allen at the University of Texas (referenced later) suggest that other sources of emissions such as pneumatic controllers and other equipment may be larger than in previous EPA estimates. This study was inconclusive about estimated emissions from liquids unloading (well clean-ups).

Gas Reporting Program,[19] with the first set of data submitted to EPA this past fall. Because the two programs differ in their scope and breadth, the total methane emission numbers for the oil and gas industry generated by each program differ somewhat as well.[20] In future years it is anticipated that the two accounting systems will be better reconciled.

The figures from both the EPA's national greenhouse gas emissions inventory and the EPA's tabulation of individual companies' emission data reports, show that the oil and gas industry is the nation's second largest industrial emitter of greenhouse gases (mainly methane and carbon dioxide), surpassed only by electric power plants.[21]

Ongoing studies will continue to advance our understanding of the methane pollution from the oil and gas industry.

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[19] EPA, Greenhouse Gas Reporting Program – Subpart W-Petroleum and Natural Gas Systems, 2011 data, available at http://www.epa.gov/ghgreporting/reporters/subpart/w.html.

[20] For example, the Reporting Program only accounts for large sources of methane (facilities that contain petroleum and natural gas systems and emit 25,000 metric tons or more of greenhouse gases per year expressed as carbon dioxide equivalents). For the purposes of this testimony I have used data from the EPA greenhouse gas inventory as a more complete representation of methane emissions from the oil and gas industry overall.

[21] EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2011, April 2013, Table ES-2, available at http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html. See also: EPA, Greenhouse Gas Reporting Program: GHGRP 2011Reported Data, Petroleum and Natural Gas Systems, available at http://www.epa.gov/ghgreporting/ghgdata/reported/petroleum.html. See also: EPA, Greenhouse Gas Reporting Program: GHGRP 2011 Reported Data, Refineries, available at http://www.epa.gov/ghgreporting/ghgdata/reported/refineries.html (reporting emissions of 182 million tons CO_2e from refineries).
Under either the inventory or the reporting rule, adding in CO_2 emissions from natural gas systems and petroleum systems places the oil and gas category in the second spot, after only power generation. It may be noted that this represents a conservative figure, as it uses a low conversion factor for translating the warming effects of methane to CO_2 equivalents, much lower than that recently published by the IPCC.

In the past three years there have been a number of studies that estimate methane emission rates in the range of 2 – 7 percent, some much higher than the figures above. It is difficult to compare these results directly due to differences in methodology, such as the use of actual emissions measurements versus estimates from engineering equations, ambient air measurements versus direct source measurements, yearly gas production versus lifetime well production, and others. Nonetheless, they give a sense of the range of uncertainty.

In August 2013, a team of scientists based in the National Oceanic and Atmospheric Administration, the University of Colorado and the University of California, published a study of methane emissions in the Uintah basin, Utah, based on atmospheric measurements. The study found that, in this particular basin, methane emissions ranged between 6 and 12 percent of hourly natural gas production levels.[22] These results may not be representative of leakage rates elsewhere.

In September 2013, a team of scientists led by fellow panelist Dr. David Allen at the University of Texas (UT) released a study of emissions from the

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[22] Karion, A., et al., Methane emissions estimate from airborne measurements over a western United States natural gas field, Geophys. Res. Lett., 40, 4393–4397, 2013, doi:10.1002/grl.50811.

production (upstream) portion of the natural gas supply chain.[23] This research is a helpful and informative addition to the growing body of data on natural gas emissions. The study found emission levels from the upstream portion of the natural gas supply chain to be roughly consistent with EPA's estimates, although at a finer grain, estimates of leakage from specific source types within that portion of the supply chain differed somewhat from EPA's estimates.

However, the data from the study speaks for only a small sample of the roughly half a million producing natural gas wells in the United States. The data is also limited to the upstream portion of the supply chain where natural gas is produced, and hence does not inform the leakage rate across the entire supply chain. The study also did not look at gas leakage from oil production specifically. As such, the data may not be representative of practices across the country. Future planned studies by UT will investigate emissions from other portions of the natural gas supply chain.

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[23] David T. Allen, Vincent M. Torres, James Thomas, David W. Sullivan, Matthew Harrison, Al Hendler, Scott C. Herndon, Charles E. Kolb, Matthew P. Fraser, A. Daniel Hill, Brian K. Lamb, Jennifer Miskimins, Robert F. Sawyer, and John H. Seinfeld, Measurements of methane emissions at natural gas production sites in the United States, Proceedings of the National Academy of Sciences (PNAS), PNAS 2013 110 (44) 17768-17773; published ahead of print September 16, 2013, doi:10.1073/pnas.1304880110.

The scientific debate on the level of methane emissions from the oil and gas industry is ongoing, and the community is developing a better understanding. Direct measurement studies will help to ascertain average emission rates from specific equipment and components, while atmospheric measurements and studies of specific locales provide a top-down estimate that may alert us to surprising emission sources. As our understanding of current emissions continues to improve, one thing we know for sure is that methane leakage can and should be reduced, as discussed in the next section of my testimony.

V. VIABLE TECHNOLOGIES ARE AVAILABLE TO CONTROL THESE EMISSIONS

Notwithstanding the range of methane leakage rate estimates, these emissions are substantial even at the lower end of the range. But on the brighter side, the technology exists to curb this leakage, simultaneously mitigating harmful impacts to community health and the climate, while generating additional revenue and profit for the oil and gas industry and other stakeholders.

Leaking Profits documents and describes ten control technologies that are technically proven, commercially available, and profitable ways for operators to capture methane that would otherwise be leaked or vented to the atmosphere. The ten technologies can be applied to various parts and processes of the supply chain: to wells during the extraction process, to processing equipment while compressing, drying or cleaning the gas, and to various components while storing and transporting it. The ten technologies surveyed by the report are briefly described below and also summarized in the inset panel.

- Green completions or reduced emissions completions: Methane emissions can occur as the well is completed (cleaned and prepared for production) by allowing the liquids, gases and other materials to flow out of the well. Green completions use processing equipment to separate the natural gas, from the liquids and other materials, which can then be captured and sold (or used onsite), thereby preventing methane emissions.
- Plunger lift systems (or similar approaches): Older wells can sometimes accumulate liquids that clog production, and methane can be vented during clean-up operations. Plunger lift systems can help reduce such emissions.
- Dehydrator emission controls: The process of removing moisture from natural gas can lead to methane leakage, and a combination of improved practices and equipment can minimize such emissions.
- Improved seals and maintenance for compressors: Compressors are used throughout the natural gas supply chain to pressurize, compress and transport

gas. Poor seals can leak methane, which can be prevented by using improved seal technology and regular maintenance.

- Low-leakage pneumatic controllers: Pneumatic controllers regulate pressure, gas flow and other characteristics of flowing natural gas. They may be designed to vent methane during normal operations. Advanced pneumatic controllers are available that emit smaller amounts of methane or none at all.
- Pipeline maintenance and repair: Techniques are available that can limit the amount of methane leaked even when pipes need to be inspected and repaired.
- Vapor recovery units: When oil and gas is stored, volatile methane can be leaked if there is inadequate sealing. Vapor recover units ensure that volatile methane (along with other pollutants) is captured.
- Leak monitoring and repair: Methane leaks across the supply chain can be reduced by employing a suite of leak detection technologies (such as infra-red cameras, electronic and acoustic gas detectors and toxic vapor analyzers), coupled with robust leak repair schedules and protocols.

1. Green completions: Using temporary processing equipment brought to a well site, fluids and gases can be routed to a tank for separation to enable sale of gas and condensate. This process, known as green completion or reduced emission completion, captures liquids and gases coming out of wells as they are being drilled, repaired, or stimulated during hydraulic fracturing.

2. Plunger lift systems: Older gas wells stop flowing when liquids accumulate inside the wellbore; methane is emitted when operators open the wells to clean out the liquids and resume gas flow. Plunger lift systems are one way to remove liquids and keep gas flowing without venting methane, extending the productive life of the well. These systems work well in mature wells and have the added advantage of not requiring separate power.

3. TEG dehydrator emission controls: Tri-ethylene glycol (TEG) dehydrators, commonly used to remove moisture from natural gas, vent methane into the atmosphere. Methane venting can be minimized, though, by retrofitting TEG dehydrating systems with emission controls and optimizing dehydration processes.

4. Desiccant dehydrators: To remove gas moisture without venting methane, desiccant dehydrators pass the gas through a bed of water-absorbing salt (the desiccant). Only a small amount of methane is released intermittently when the salt is replaced. Desiccant dehydrators are best suited to wells with low gas flow rates and temperatures.

5. Dry seal systems: Throughout the oil and gas industry, dry seals can be used to reduce emissions from the centrifugal compressors that move gas efficiently through pipelines. Most new centrifugal compressors have dry seals, which use gas to create high-pressure barriers that prevent leaks.

6. Improved compressor maintenance: Replacing worn rod packing, as part of an improved compressor maintenance program, can prevent methane leaks.

7. Low-bleed or no-bleed pneumatic controllers: Pneumatic controllers control pressure, gas flow, and liquid levels, and automatically operate valves. Pneumatic controllers may be designed to release (bleed) methane to the atmosphere as part of normal operations. Methane emissions can be reduced by replacing high-bleed controllers with low- or no-bleed ones, retrofitting with bleed-reduction kits, or converting gas-based pneumatics to air-based pneumatics.

8. Pipeline maintenance and repair: When a pipeline is repaired or replaced, or cut to install a new connection point, methane is traditionally released into the atmosphere. The amount of methane vented can be reduced by connecting a new pipe to the system while it remains in operation, removing gas with compressors, or de-pressurizing the pipeline to flow gas to a nearby low-pressure fuel system.

9. Vapor recovery units (VRUs): Crude oil containing natural gas or gas liquids (condensates) is sometimes stored in tanks. Methane can escape from the tanks during agitation of the liquids, during transportation or storing, or even while standing. VRUs comprising scrubbers, compressors, and valves can capture up to 95 percent of the methane that would otherwise be vented.

10. Leak monitoring and repair: Methane leaks can occur from numerous locations at an oil and gas facility—valves, drains, pumps, connections, pressure relief devices, open-ended valves, and lines. These leaks are called fugitive emissions. Since methane is a colorless, odorless gas, methane leaks often go unnoticed. A well-implemented program of regularly monitoring and repairing leaks can significantly reduce fugitive emissions.

Each of these technologies has been implemented successfully by a number of oil and gas companies and operators in some of their operations, such as Anadarko, BP, ConocoPhillips, Chevron, Devon, EnCana, Southwestern and Williams, to name a few. Unfortunately, they are not universally adopted industry-wide. The operational performance of the control technologies are also found to be very favorable in studies conducted by the EPA Natural Gas STAR program.[24] (The Natural Gas STAR program also provides guidance on the use of these and many other emission control technologies.)

Leaking Profits also analyzes the costs and benefits of the technologies, and summarizes and compares their commercial viability across a number of implementation instances (as shown in the table below). It finds that the technologies are very cost-effective, paying for themselves in less than one to three years. Typically these emission control technologies require an upfront investment, either for a retrofit or for specific components on newly installed equipment. The control technologies generate additional revenue by reducing wasted gas, which can be sold to the market or used onsite (thereby offsetting fuel costs). The control

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[24] EPA, Natural Gas STAR Program, available at http://www.epa.gov/gasstar/.

technologies sometimes need additional operations and maintenance, but on many occasions produce savings on that front as well.

Methane Capture Technology Costs and Benefits

Technology	Investment Cost	Methane Capture	Profit	Payout
Green Completions	\$8,700 to \$33,000 per well	7,000 to 23,000 Mcf/well	\$28,000 to \$90,000 per well	< 0.5 – 1 year
Plunger Lift Systems	\$2,600 to \$13,000 per well	600 to 18,250 Mcf/year	\$2,000 to \$103,000 per year	< 1 year
TEG Dehydrator Emission Controls	Up to \$13,000 for 4 controls	3,600 to 35,000 Mcf/year	\$14,000 to \$138,000 per year	< 0.5 years
Desiccant Dehydrators	\$16,000 per device	1,000 Mcf/year	\$6,000 per year	< 3 years
Dry Seal Systems	\$90,000 to \$324,000 per device	18,000 to 100,000 Mcf/year	\$280,000 to \$520,000 per year	0.5 – 1.5 years
Improved Compressor Maintenance	\$1,200 to \$1,600 per rod packing	850 Mcf/year per rod packing	\$3,500 per year	0.5 years
Pneumatic Controllers Low-Bleed	\$175 to \$350 per device	125 to 300 Mcf/year	\$500 to \$1,900 per year	< 0.5 – 1 year
Pneumatic Controllers No-Bleed	\$10,000 to \$60,000 per device	5,400 to 20,000 Mcf/year	\$14,000 to \$62,000 per year	< 2 years
Pipeline Maintenance and Repair	Varies widely	Varies widely but significant	Varies widely by significant	< 1 year
Vapor Recovery Units	\$36,000 to \$104,000 per device	5,000 to 91,000 Mcf/year	\$4,000 to \$348,000 per year	0.5 – 3 years
Leak Monitoring and Repair	\$26,000 to \$59,000 per facility	30,000 to 87,000 Mcf/year	\$117,000 to \$314,000 per facility per year	< 0.5 years

Note: Profit includes revenue from deployment of technology plus any O&M savings or costs, but excludes depreciation.

VI. THE TECHNOLOGIES HAVE THE POTENTIAL TO REDUCE EMISSIONS DRASTICALLY

Leaking Profits estimated that, together, the ten technologies discussed in this report could address and potentially reduce more than 80 percent of emissions from the oil and gas industry. This is equivalent to reducing gross emissions to under half a percent of yearly natural gas production. (As explained earlier, curtailing methane emissions to this extent can maximize the advantage of natural gas relative to coal and other fossil fuels.)

In making this estimate, *Leaking Profits* assumed nearly complete technical applicability and feasibility of these emission control technologies, and sufficient time for the deployment of these technologies, industry-wide. A detailed analysis of the technical feasibility of technology deployment was beyond this study's scope. Nonetheless, *Leaking Profits* provides a sense of the considerable extent to which these ten technologies are applicable and their potential for emissions reductions. (Even using EPA's lower leak rate estimate (1.5 percent vs. 2.4 percent), the ten technologies could still address and potentially reduce a high percentage of emissions, in the vicinity of 60 - 80 percent.)

The recent study led by Dr. David Allen at UT throws light on the efficacy of emission control technologies in operation. The effectiveness of green completions (and flaring in its absence) in reducing emissions was clearly demonstrated. Across a sample of 27 wells undergoing completions, the potential emissions[25] were consistent with those in EPA's national inventory. Actual emissions measured from these completed wells were found to be significantly reduced (on average by 98 percent), largely due to the fact that many of the wells

[25] The methane that would be emitted if all of the methane leaving the wellhead during the process of completion flowback were vented to the atmosphere.

had implemented practices to minimize emissions, such as those akin to green completions or flaring.

On the other hand, the study found that the leakage rate from low-bleed pneumatic controllers in practice were higher than previously estimated by the EPA. This suggests room for further improving the control technologies. The study was inconclusive about the magnitude of emissions from well clean-ups (liquids unloading), which may be controlled by plunger lift systems.

VII. VOLUNTARY ACTIONS ARE INSUFFICIENT TO CONTROL METHANE EMISSIONS

In light of the fact that methane controls have been shown to be profitable, a commonly asked question is: "Why doesn't the oil and gas industry voluntarily invest in methane emission control?"

In some limited cases, site-specific factors, such as flow rate, temperature, and low gas pressure, render the control of methane emissions technically infeasible or unprofitable. However, for most of the methane control technologies highlighted in this report, ensuring that companies use the technologies is more a matter of modernizing outmoded business practices, commanding resource and budget allocations, and instilling a corporate commitment to greenhouse gas emission reduction.

The American Petroleum Institute (API) explains that in order to maximize profit and provide shareholders with the highest possible return on investment, the oil and gas industry operates with a strict ranking of capital projects for maximum yield.[26] Thus, even though methane control measures are profitable, they are often crowded off the list of corporate investment projects by other investments with an even higher rate of return or lower perceived risk profile. Even with payback periods ranging from immediate to three years, some companies apparently view these leak prevention technologies as not attractive enough to meet the oil and gas companies' extraordinarily high expected rates of return on other projects. In yet other cases, accounting factors, and short- and long-term acquisition and divestment strategies, can frustrate even high-return, low-capital methane reduction projects. The public benefits of emission control measures are entirely ignored.

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[26] American Petroleum Institute (API) and the International Petroleum Industry Environmental Conservation Association (IPIECA), Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects, prepared by URS Corporation, March 2007. On page 18, the document concludes that "Companies and investors operate under capital constrains and the estimated financial returns of such GHG reduction projects may not justify diverting capital from other higher return or more strategic initiatives."

In short, a few leading oil and gas companies have implemented a subset of standards in some of their operations. But many others have not.

Thus, there is an especially compelling case for fixing market failures that ignore public benefits – a case where standards limiting greenhouse gas emissions turn a profit, even if one smaller than some oil and gas companies seem to desire. This is why NRDC concludes that standards are needed to level the playing field, as we cannot rely on all companies to adopt even profitable methane control technologies voluntarily.

VIII. RECENTLY ESTABLISHED EPA STANDARDS BEGIN TO CONTROL THESE EMISSIONS

In April 2012, the EPA finalized performance standards for certain new and modified sources of emissions from the oil and gas industry. These were published in the Federal Register in August 2012.[27] These standards target volatile organics emissions and hazardous air pollutants, but they have the co-benefit of reducing methane emissions from some emission sources in the natural gas supply chain,

[27] EPA, 40 CFR Parts 60 and 63, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews: Final Rule, Federal Register, Vol. 77, No. 159, August 16, 2012, Page 49490-49600.

particularly in the upstream production and processing portions. (I note here that when there is appreciably less volatile organics and hazardous air pollutants present in the natural gas streams, such as in the transportation and distribution portions of the supply chain, these standards are much less effective at reducing methane emissions.)

These standards were a long-awaited and important update after several decades in which only very weak and limited EPA requirements had applied to the industry. But while they are a good first step in the right direction, they leave significantly more work to be done regarding methane.

The standards require a number of control technologies, almost all of which are discussed in *Leaking Profits* and found to be cost-effective and profitable.

The standards require the use of green completions by 2015 (and in the interim any emissions will have to be flared). Emissions reductions from this portion of the standards constitute the majority of expected reductions associated with the rulemaking. These standards only cover wells whose primary purpose is to produce gas, a loose definition that may not apply to oil wells that co-produce large amounts of gas.

The standards will also require low-leakage (low-bleed) pneumatic devices, improved seals and maintenance for compressors, vapor recovery units, and leak detection and repair. But these standards cover only new or modified equipment in limited parts of the supply chain. For instance, the standards do not cover most existing equipment already operating in the field. Additionally, they do not cover most leaking equipment further downstream from where natural gas is produced (wells) and processed, such as in the storage, long-distance transportation and local distribution portions of the natural gas supply chain. Hence, the magnitude of expected reductions from these standards is a small percentage of the total methane from the industry.

As such, in the near-term we estimate that the EPA standards will reduce approximately 10-15 percent[28] of the industry's total annual emissions. As old equipment is replaced over time and new equipment becomes subject to the standards, by 2035, annual emissions reductions could increase to approximately 25-30 percent of the total.[29]

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[28] This number would depend on the size of the total emissions inventory (noting that there has been and continues to be uncertainty in these emissions), as well as other factors such as the technical applicability of the standards, exemptions and enforcement.

[29] James Bradbury, Michael Obeiter, Lauren Draucker, Wen Wang, Amanda Stevens, Clearing the Air: Reducing Upstream Greenhouse Gas Emissions from U.S. Natural Gas Systems, published by World Resources Institute, April 2013, available at http://www.wri.org/publication/clearing-air.

The table below is a summary of what emission sources the EPA standards would cover, along with other sources that similar standards could have cost-effectively covered (as per our analysis) but are not required to.

Summary of Application of EPA Emission Standards to Oil and Gas Industry		
Equipment / Emission Sources and Associated Emission Reduction Strategies Required ("Required") vs. Equipment / Emission Sources and Cost-Effective Emission Control Strategies Available but Not Required ("Not Required")		
Wells	**Required**	**Not Required**
New Natural Gas Wells Drilled and Completed using Hydraulic Fracturing	Green completions	
New Wild Cat Exploration, Delineation, and Low Pressure Wells	Emission control device	
Gas Wells Refractured	Green completions	
Gas Well Venting - Liquids Unloading / Well Clean-Ups (Existing Wells)		No: Green completions
Gas Well Venting - Liquids Unloading / Well Clean-Ups (New Wells)		No: Green completions
Pneumatic Controllers	**Required**	**Not Required**
Oil and Gas Production Segment: Pneumatic controllers >6 scfh installed after 8-23-11.	Low-bleed devices	
Gas Processing Plant Segment: All pneumatic controllers in installed after 8-23-11.	No-bleed devices	
Oil and Gas Production and Gas Processing Plant Segments: Existing high-bleed devices.		No: Low-bleed devices / no-bleed devices
Transportation and Storage Segments: Existing high-bleed devices.		No: Low-bleed devices / no-bleed devices
Transportation and Storage Segments: Pneumatic controllers installed after 8-23-11.		No: Low-bleed devices / no-bleed devices
Compressors	**Required**	**Not Required**
New Gas Production (Gathering & Boosting) Reciprocating Compressors	Improved compressor maintenance	
New Gas Processing Plant Reciprocating Compressors	Improved compressor maintenance	
New Gas Processing Plant Centrifugal Compressors	Dry seals / emission control device	
New Wellhead Reciprocating Compressors		No: Improved compressor maintenance
New Transmission Reciprocating Compressors		No: Improved compressor maintenance
New Storage Reciprocating Compressors		No: Improved compressor maintenance
New Transmission and Storage Centrifugal Compressors		No: Dry seals
Existing Oil and Gas Reciprocating Compressors		No: Improved compressor maintenance
Existing Oil and Gas Centrifugal Compressors		No: Dry seals
Storage Vessels	**Required**	**Not Required**
New Storage Vessels >6 tpy VOC	Vapor recovery units / emission control	
Existing Storage Vessels > 6tpy		No: Vapor recovery units
Equipment Leaks	**Required**	**Not Required**
New Gas Processing Plants	Leak detection and repair	
New Well Pads; Control of Valves Only		No: Leak detection and repair
New Gathering & Boosting Facilities; Control of Valves Only		No: Leak detection and repair
New Transmission & Storage Facilities; Control of Valves Only		No: Leak detection and repair
Existing Oil & Gas Sector Equipment Leaks		Limited leak detection and repair

IX. STANDARDS CAN GO MUCH FURTHER TO CONTROL EMISSIONS

Clearly, referring to the above table, emission control standards can go much further. NRDC recommends that the federal government require the following additional measures to reduce methane emissions further:

- Controls for existing equipment (not just new or modified ones), particularly existing compressors and pneumatic controllers, for which reducing emissions is particularly cost-effective.
- Green completions (or other emission control practices) for associated or co-producing wells, which produce both oil and gas.
- Plunger lift systems (or similar approaches) at existing gas- or oil-producing wells that vent methane during clean-up operations.
- Rigorous leak detection and repair protocols that are able to detect a variety of leaks, efficiently over the numerous sources within the oil and gas industry, and repair them effectively and in a timely fashion.
- A suite of emission control measures that apply to the downstream portion of the natural gas supply chain where gas is stored, transported and piped to residential, commercial and industrial end-users. This includes leak detection and repair of corroded and leaky pipelines; replacement of leaking pneumatic

controllers, compressors and other components; and the use of smart pipeline repair techniques that vent less methane.

In addition to standards that target hazardous air pollutants and volatile organic compounds, standards should be designed to directly target methane emissions. This would enable reaching all significant sources of methane emissions throughout the natural gas supply chain, including those not addressed by recently-established standards targeting other pollutants. This would also facilitate the most appropriate standards for methane emission control, and a more accurate reflection of the cost-effectiveness of such standards.

Additionally, all of these actions would be entirely consistent with the President's Climate Action Plan, which includes an Interagency Methane Strategy led by the EPA, which will seek to analyze emission sources, identify and improve control technologies and best practices, establish incentives, and coordinate agency action to achieve meaningful emission reductions.

I also note that, also consistent with the Climate Action Plan, these actions will help achieve a collaborative approach among government and a number of industrial sectors, which would be self-reinforcing and beneficial to the wider economy. For example, for companies that lack the technical expertise or staff resources in house, there are excellent federal resources (such as EPA's Natural

Gas STAR program that provides technical guidance on methane control) and private service providers. The installation, operation and maintenance of pollution control equipment create jobs and revenue for service providers and/or oil and gas producers; increased spending in this regard would especially be a boon for smaller regional service companies. Additionally, emission control standards would also create extensive opportunities for the manufacture of necessary equipment and pipes in the United States[30]; furthermore, such opportunities, supported by successful programs like EPA's Natural Gas STAR can lead to innovation and improvement of technologies and standards. Robust leak detection and repair practices that reduce emissions and improve industry safety would create employment for well-trained workers such as pipeline technicians and natural gas facility operators; various labor groups such as United Steelworkers and the BlueGreen Alliance are eager to partner with the government in this regard.

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[30] Richard Heidorn, Bloomberg Government, Fracking Emission Rules: EPA, Industry Miss Mark on Costs, Consequences, July 2012, available at http://about.bgov.com/2012-07-19/fracking-emissions-rules-re-estimating-the-costs/.

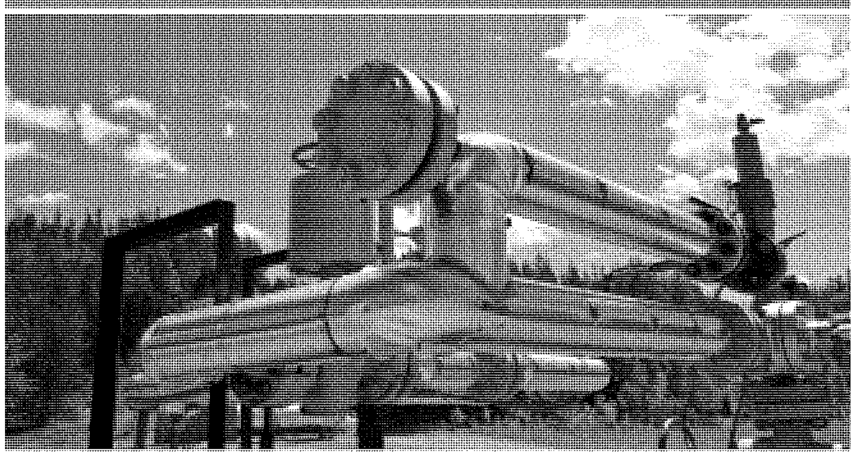
X. CONCLUSION

In closing, I would like to summarize and underscore the central message of this testimony. A considerable amount of methane, along with other harmful air pollutants, is currently being leaked and vented from the oil and gas industry. Emissions control technologies and associated practices to significantly limit such pollution exist today, have been tried and tested, and are being used by some oil and gas producers in the field already. These are also commercially cost-effective and profitable, and can generate value for the broader economy. But voluntary implementation of these profitable measures has not occurred comprehensively across the industry to satisfactorily limit emissions. Hence, there is a strong justification to fix these market failures, and establish emission control standards that will help to ensure environmental and community safety, while generating economic value. The recently-established EPA emission standards for the oil and gas industry are an important first step in the right direction. The recent study led by researchers from the University of Texas confirms that industry emissions are significant, but that such standards do work and can be very effective at reducing these emissions. However, other emission control standards can be much improved and the federal government should take the lead in establishing such standards.

Leaking Profits

The U.S. Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste

March 2012



Principal Author
Susan Harvey, Harvey Consulting, LLC
Contributing Authors
Vignesh Gowrishankar, Ph.D., Natural Resources Defense Council
Thomas Singer, Ph.D., Natural Resources Defense Council

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About the Natural Resources Defense Council
The Natural Resources Defense Council is a national nonprofit environmental organization with more than 1.3 million members and online activists. Since 1970, our lawyers, scientists, and other environmental specialists have worked to protect the world's natural resources, public health, and the environment. NRDC has offices in New York City, Washington, D.C., Los Angeles, San Francisco, Chicago, Montana, and Beijing.

About Harvey Consulting LLC
Susan Harvey has 25 years of experience as a Petroleum and Environmental Engineer, working on oil and gas exploration and development projects. Ms. Harvey is the owner of Harvey Consulting, LLC, a consulting firm providing oil and gas, environmental, regulatory compliance advice and training to clients. Ms. Harvey held engineering and management positions at both Arco and BP. Ms. Harvey has planned, engineered, executed and managed both onshore and offshore exploration and production operations, and has been involved in the drilling, completion, stimulation, testing and oversight of hundreds of wells in her career. Ms. Harvey's experience also includes air and water pollution abatement design and execution, best management practices, environmental assessment of oil and gas project impacts, and oil spill prevention and response planning. Ms. Harvey taught air pollution control engineering courses at the University of Alaska in the Graduate Engineering Program.

NRDC Director of Communications: Phil Gutis
NRDC Deputy Director of Communications: Lisa Goffredi
NRDC Publications Director: Alex Kennaugh
NRDC Editor: Jennifer Freeman
Design and Production: Tanja Bos

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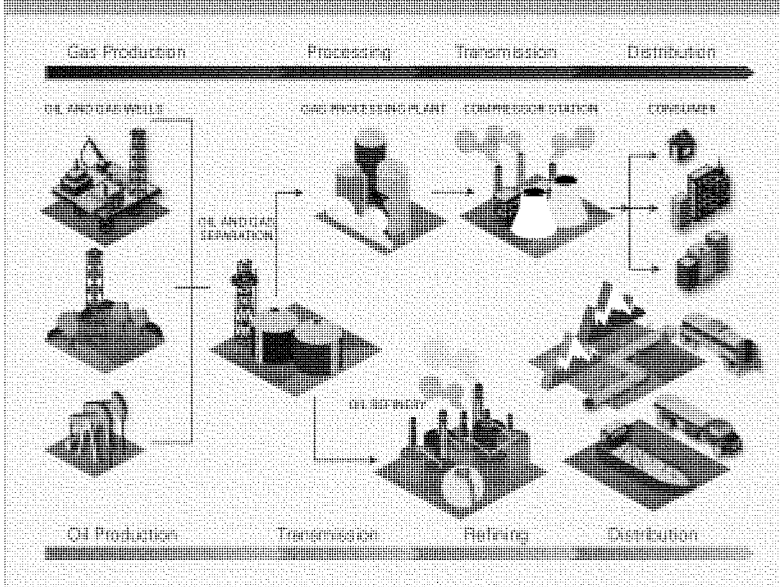
1. EXECUTIVE SUMMARY

Methane is valuable as a fuel, but it is also a greenhouse gas at least 25 times more potent than carbon dioxide over a 100 year period, with even greater relative impacts over shorter periods. Methane makes up as much as 90 percent of natural gas. Currently the United States loses at least 2 to 3 percent of its total natural gas production each year when gas is leaked or vented to the atmosphere. Natural gas is routinely allowed to escape into the atmosphere from oil and gas industry equipment and processes. This is a waste of a valuable fuel resource as well as a source of local pollution and climate change.

A focus on reducing methane waste can produce not only benefits for the climate but also substantial profits for oil and gas companies, and revenues for royalty owners including taxpayers, who own public lands. This report focuses on 10 profitable and widely applicable methane emission reduction opportunities in the United States oil and gas (O&G) industry. If these technologies could be used throughout the industry, they have the potential to reduce U.S. methane emissions by more than 80 percent of current levels, based on the U.S. Environmental Protection Agency's (EPA) estimates, an amount greater than the annual greenhouse gas emissions from 50 coal fired power plants. This methane, if captured and sold, can bring in billions of dollars in revenues while benefiting the environment.

A combination of voluntary and mandatory programs implemented by the EPA and many states has already reduced the industry's U.S. methane emissions by more than 20 percent. Given industry practice to date, it appears that available control technologies, while profitable, do not provide sufficient incentive to drive further voluntary reductions. While voluntary programs have resulted in some progress, additional mandatory programs are needed to get closer to the more than 80 percent methane reduction level that this report demonstrates could be within our reach.

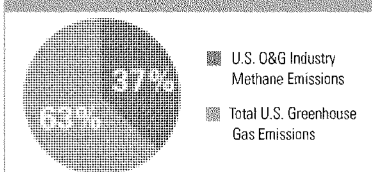
Figure 1: Oil and Gas Production, Processing, Transmission, Refining, and Distribution System Simplified Schematic



The U.S. O&G industry, which includes both liquid petroleum (crude oil, condensate, and natural gas liquids) and natural gas systems (Figure 1), produced 26,000 Bcf (billion cubic feet) of gas in 2009.[1] The industry lost an estimated 623 Bcf of methane to the atmosphere in 2009, a loss of 2.4 percent of the total U.S. gas produced. This amount of methane, 623 Bcf, is roughly 37 percent of total U.S. methane emissions (Figure 2).[2] Natural gas systems contribute most of the O&G industry's methane emissions, 547 Bcf/year (88 percent of the total). Liquid petroleum systems, which currently result in methane emissions of about 76 Bcf/year (12 percent of the total), represent an additional emission source (Table 1).

The 10 technologies covered in this report are technically proven, commercially available, and profitable ways for operators to capture methane that would otherwise be leaked or vented to the atmosphere from oil and gas production, processing and transportation systems.[3] These 10 methane control solutions are only a starting point for the O&G industry. The EPA's Natural Gas STAR Program, the O&G industry, and equipment vendors have identified nearly 100 methane control options that have merit.[4] We selected these 10 technologies because they have been proven by the EPA and industry to be both profitable and technically feasible, time and time again.

Figure 2: Methane from the O&G Industry as a Percent of Total U.S. Methane Emissions



Note: Methane made up 10.3 percent of U.S. greenhouse gas emissions in 2009.
Source: U.S. EPA 2011 *Greenhouse Gas Inventory*

Together, these 10 technologies have the ability to capture more than 80 percent of the O&G sector's methane emissions if they could be deployed industry-wide:

1. **Green Completions** to capture oil and gas well emissions
2. **Plunger Lift Systems** or other well deliquification methods to mitigate gas well emissions
3. **Tri-Ethylene Glycol (TEG) Dehydrator Emission Controls** to capture emissions from dehydrators
4. **Desiccant Dehydrators** to capture emissions from dehydrators
5. **Dry Seal Systems** to reduce emissions from centrifugal compressor seals
6. **Improved Compressor Maintenance** to reduce emissions from reciprocating compressors
7. **Low-Bleed or No-Bleed Pneumatic Controllers** used to reduce emissions from control devices
8. **Pipeline Maintenance and Repair** to reduce emissions from pipelines
9. **Vapor Recovery Units** used to reduce emissions from storage tanks
10. **Leak Monitoring and Repair** to control fugitive emissions from valves, flanges, seals, connections and other equipment

Methane control technologies provide economic, health, safety, and environmental benefits for both operators and the public. These control technologies reduce not only greenhouse gas emissions, but also potentially explosive vapors, hazardous air pollutants, and volatile organic compounds (VOC), improving worker safety and limiting corporate liability. Using these technologies, captured methane can be turned into a supply of natural gas to meet ever-growing market demands, or used as a source of energy for operations. When development occurs on public lands, use of the technologies can result in royalty payments to the government from the sale of captured methane, as well as improved stewardship of our natural resources.[5]

In its 2011 *Greenhouse Gas Inventory*, the EPA estimated that the O&G industry reduced emissions by 168 Bcf in 2009. At a price of $4 per thousand standard cubic foot (Mcf), the industry generated $672 million in gross revenue by keeping this gas in the revenue stream. About a quarter (39 Bcf) of the emissions reductions came from Federal regulations such as NESHAPs (National Emission Standards for Hazardous Air Pollutants), and three quarters (129 Bcf) from voluntary emissions reductions under the EPA's Natural Gas STAR program.

The 10 technologies discussed in this report could potentially capture more than 80 percent of the 623 Bcf wasted by the O&G industry. Selling this methane at the average 2011 price of $4/Mcf would generate more than $2 billion annually.

This is equivalent to reducing greenhouse gas emissions from more than:

- 40,000,000 passenger vehicles
- The electric use of 25,000,000 homes
- 50 coal fired power plants, or
- 500,000,000 barrels of oil[6]

Despite these environmental and financial benefits, in some instances there are technical, financial and institutional barriers that prevent O&G operators or companies from voluntarily investing in methane control. Nevertheless, most of the methane control technologies highlighted in this report can be achieved simply by modernizing outmoded business practices, commanding resource and budget allocations, and instilling a corporate commitment to methane emission reduction. If better operating conditions and profits are not enough incentive to implement these projects, policies that mandate emissions control will be necessary to achieve the full potential of these methane control technologies.

EMISSION REDUCTION POTENTIAL OF 10 PROFITABLE TECHNOLOGIES

Each methane emission control technology evaluated in this report contributes to the goal of treating methane as a valued resource and keeping it out of the atmosphere. Just two methane control technologies, green completions and plunger lift systems, can potentially address nearly 40 percent of methane emissions (Figure 3). All 10 technologies discussed in this report together could address an estimated 88 percent of emissions from the O&G industry. This is equivalent to reducing gross emissions from 3 percent of production to about 0.4 percent of production.

The estimate of potential emissions reductions from these ten technologies assnmes nearly complete technical feasibility for all sources in a category, and sufficient time for the deployment of these technologies industry-wide. A detailed analysis of the technical feasibility of technology deployment is beyond the scope of this report. The estimate includes cumulative emissions reductions possible, i.e., not incremental to any reductions already made.

Table 1: Methane Emissions (in Billion Cubic Feet)

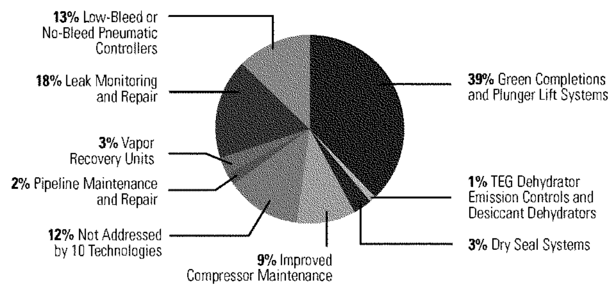
	Natural Gas System	Petroleum System	O&G Industry
Gross emissions	715	76	791
Emissions reductions*	168	-	168
Net emissions	547	76	623

*From Natural Gas STAR program and federal regulations
Source: U.S. EPA 2011 *Greenhouse Gas Inventory*

Only gross emissions estimates are available from the EPA in sufficient detail by source to use as a basis for analysis. The following emissions estimates, from the EPA's 2011 *Greenhouse Gas Inventory*, are based on gross emissions (corresponding to total gross emissions of 791 Bcf/year).[7]

- **Green completions,** also known as reduced emissions completions, are closed loop systems that capture liquids and gases coming out of the well during "completions" using temporary processing equipment brought to a well

Figure 3: O&G Industry Methane Emission Reduction Potential by Technology



Note: 2009 gross O&G industry methane emission was 791 Bcf. The 10 technologies can address all but 12 percent of these emissions. Based on data from U.S. EPA 2011 *Greenhouse Gas Inventory.*

site, then routing fluids and gases to a tank for separation to enable sale of gas and condensate. Historically, the fluids and gases flowing back out of the well have been routed to an open air pit or perhaps a tank, allowing substantial amounts of methane to vent directly into the atmosphere. The EPA estimates that approximately 8,200 Mcf of natural gas is emitted per well completion, on average. Well completions, workovers and cleanups emit approximately 305 Bcf gross of methane per year. Green completions may be used to control considerable emissions from well completions and workovers (68 Bcf). Green completions can also be used to control a portion of the 237 Bcf/year in emissions from cleanups of low pressure wells (also known as liquids unloading).

- **Plunger Lift Systems** are installed on gas wells that stop flowing when liquid (water and condensate) accumulates inside the wellbore. These systems lift accumulated liquids in the wellbore to the surface. Using this method, methane gas can be captured and sold rather than vented to atmosphere as waste. Approximately 4,500 to 18,000 Mcf/year of methane gas is emitted per well, mainly from normal cleanup operations. This contributes to the EPA's estimate of total gross emissions of 237 Bcf/year from liquids unloading.

- **TEG Dehydrator Emission Controls** or Desiccant Dehydrators can be used to reduce methane waste while removing moisture from natural gas from oil or gas wells. Methane is often vented during the process of dehydrating gas, but it can be captured using either emission control equipment placed on TEG dehydrators, or with desiccant dehydrators. Desiccant dehydrators dry gas by passing it through a bed of sacrificial hygroscopic salt (the desiccant); there are no pumps, contactors, regenerators, or reboilers. Only a small amount of methane is released intermittently when the unit is opened to replace the salt. Desiccant dehydrators are best suited for low gas flow rates and low gas temperatures. Alternatively, where glycol dehydrators are still required, there are emission control solutions that can capture methane gas for use as fuel. The EPA estimates that 20,000 Mcf/year of natural gas is emitted per well on average (including both old and new wells), and that smaller dehydrators still cumulatively emit approximately 8 Bcf of methane per year despite mandatory emission controls on most large dehydrator systems. A significant fraction of this 8 Bcf/year of gross emissions from this source can and should be captured.

- **Dry Seal Systems** can be used throughout the O&G industry to reduce emissions from centrifugal compressors that compress natural gas so that it can be efficiently moved through a pipeline. Methane can leak from the seals in centrifugal compressors and the rod packing mechanisms in reciprocating compressors. Installation of improved dry seals in centrifugal compressors, and **improved compressor maintenance** by replacing worn rod packing in reciprocating compressors, have the potential to significantly reduce the amount of methane emitted. The EPA estimates that leaking compressors emit about 102 Bcf/year (27 Bcf/year from centrifugal compressors and 75 Bcf/year from reciprocating compressors). A significant fraction of this can and should be captured.

- **Low-Bleed or No-Bleed Pneumatic Controllers** can be used throughout the O&G industry to reduce emissions while regulating pressure, gas flow, and liquid levels, and automatically operating valves. High-bleed pneumatic devices are designed to release methane gas to the atmosphere. Converting high-bleed gas devices to low-bleed devices, or moving away from gas-operated devices altogether in favor of instrument air, reduces methane emissions. The EPA estimates that 80 percent of all high-bleed pneumatic devices can be retrofitted, and that there is an opportunity to reduce a very large fraction of the 99 Bcf/year of gross methane emissions from pneumatic controllers.

- **Pipeline Maintenance and Repair** can result in methane venting to the atmosphere when an oil or gas pipeline is cut or when methane is vented to reduce potential fire or explosion risk while the pipe is under repair. Instead, to mitigate methane release, subject to a thorough safety evaluation, gas can either be re-routed and burned as fuel during the repair and maintenance, or work can be conducted on the pipeline while it is in operation. Methane gas venting can also be mitigated by using hot tap connections, de-pressuring the pipeline to a nearby low pressure fuel system, or using a pipeline pump-down technique to route gas to sales. The EPA estimates that pipeline maintenance and upset conditions requiring venting result in emission of 19 Bcf of methane per year, a sizeable fraction of which can and should be captured.

- **Tank Vapor Recovery Units (VRUs)** capture methane that otherwise would escape from crude oil and condensate tanks and be vented to the atmosphere through three different mechanisms: (1) flashing losses, (2) working losses, and (3) standing losses. To reduce these losses, a vapor recovery unit can be installed on the tank to capture methane gas for sale or for use as fuel. The EPA estimates these methane emissions amount to about 21 Bcf/year, a sizeable fraction of which can and should be captured. In addition to methane, tank vapor recovery units can also reduce emissions of hazardous air pollutants (HAPs), such as benzene, toluene, ethylbenzene, xylenes, and volatile organic compounds (VOCs).

- **Leak Monitoring and Repair** prevents leaks at oil or natural gas facilities that would otherwise result in fugitive methane emissions, which may occur due to normal wear and tear, improper or incomplete assembly of components, inadequate material specifications, manufacturing defects, damage during installation or use, corrosion, or fouling. As gas moves through equipment under high pressure, methane gas leaks can occur from numerous locations at oil and gas facilities: valves, drains, pumps, threaded and flanged connections, pressure relief devices, open-ended valves and lines, and sample points. Because methane is a colorless, odorless gas, methane leaks often go unnoticed. Leak monitoring programs, and prompt repair when leaks are detected, can be effective in controlling fugitive emissions. Control can be achieved through a two-part process: (1) a monitoring program to identify leaks, and (2) a repair program to fix the leaks. The EPA estimates that equipment leaks result in gross emissions of 143 Bcf of methane per year. A large part of this may be controlled by improved leak monitoring and repair programs.

POLICY RECOMMENDATIONS

The EPA's *Greenhouse Gas Inventory* in recent years represents the agency's best current understanding of methane emissions from the O&G industry based on available data, recognizing that significant uncertainties exist. Changes to the inventory in recent years highlight challenges in understanding methane emissions from the O&G industry. NRDC calls upon the industry to provide improved data to aid the EPA in resolving uncertainties. NRDC strongly supports rigorous, mandatory reporting, especially from numerous small sources that in aggregate may result in significant emissions. Improved data can support more robust analyses of methane emissions, which will help with the development of appropriate emissions reduction solutions.

In its 2011 *Greenhouse Gas Inventory*, the EPA provides an excellent breakdown of emissions by both O&G sector (production, processing, transmission) and by source. It does not, however, provide enough detail of emissions reduction by leakage source. Emissions reduction is only identified at a broad sector level. NRDC recommends that the EPA provide a more detailed breakdown of emissions reduction by leakage source.

On broader policies to control methane emissions, NRDC supports the EPA's steps to improve the O&G industry proposed New Source Performance Standards (NSPS) to control VOCs, which will achieve significant methane reduction co-benefits.[8] For example, methane emitted during well completions and recompletions will be controlled to a much larger extent once the proposed VOC regulations are implemented. The EPA's proposed NSPS regulations are a good starting point.

However, NRDC recommends that the EPA's proposed NSPS regulations go much further.[9] First, the EPA should directly regulate methane. In addition, while the EPA has proposed federal performance standards for new and modified sources, the proposal does not cover the many existing sources of methane. The EPA should issue guidelines for existing sources, which states would then be required to adopt through their State Implementation Plans. The EPA's guidelines should cover all significant sources of emissions, and all segments of the natural gas supply chain, and require compliance with stronger standards and procedures.

While the Natural Gas STAR voluntary program has achieved some success in controlling methane emissions, mandatory control requirements such as under the NSPS and NESHAPs programs are necessary for greater industry-wide emissions reductions.

Federal land management agencies should also exercise their authority to control methane waste from oil and gas lease operations on federal lands.

Finally, state governments also can do more to require methane emission controls. Colorado, Montana, and Wyoming have rules covering existing methane emission sources including wells, pneumatic devices, and storage tanks. While these rules provide a good start, they and other states should develop even stronger regulations.

2. METHANE CONTROL: OPPORTUNITIES AND ISSUES

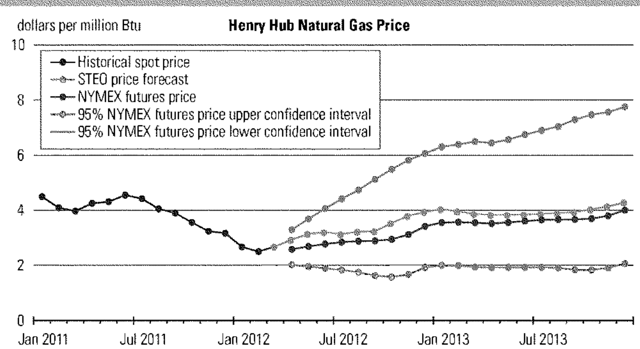
There is well established international scientific consensus, as demonstrated in the findings of the Intergovernmental Panel on Climate Change and the National Academy of Sciences, that greenhouse gas emissions are a significant cause of climate change. Methane gas is a well known and well-documented greenhouse gas, with a much greater global warming potential than carbon dioxide on a mass basis. Significant greenhouse gas emission controls, and methane emission control in particular, help to mitigate global warming.

Methane is the primary component of natural gas, which typically contains 80 to 90 percent methane, ranging up to as high as 98 percent in some cases.[10] Every standard cubic foot (scf) of methane gas lost to the atmosphere is a standard cubic foot of methane not sold—a direct, real, and measurable loss of revenue. Methane control ensures that the gas produced at the well is kept in the revenue stream.[11]

Not only are methane capture projects in the O&G industry critical for addressing the climate crisis, but such projects also can be profitable, improve safety, maximize energy resources, reduce economic waste, protect human health, and reduce environmental impacts. Furthermore, upgrading production assets with modern and efficient equipment has improved operational and economic performance, making assets more robust and less susceptible to upsets and downtime.

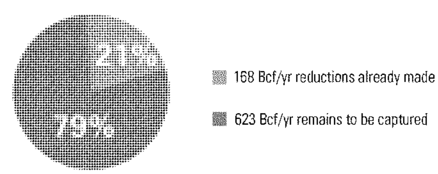
Using a gas price of $4/Mcf, based on average 2011 prices, every Bcf of methane captured and sold, rather than vented into the atmosphere, can generate approximately $4 million in gross revenue. The EPA used $4/Mcf as a conservative estimate in its 2011 NSPS proposed rulemaking (Figure 4). Many of the control technologies pay out their investment and start generating profits after a short period of time for the O&G industry, as well as those, including the U.S. government, who receive royalties and taxes on gas sales.

Figure 4: Current Average Gas Price $4 Per Methane Cubic Square Feet



Note: Confidence interval derived from options market information for the 5 trading days ending March 1, 2012
Intervals not calculated for months with sparse trading in "near-the-money" options contracts
Source: U.S. Energy Information Administration, Short-Term Energy Outlook, March 2012

Figure 5: O&G Industry Methane Reduction and Remaining Opportunity



Source: U.S. EPA 2011 *Greenhouse Gas Inventory*

2.1 INCENTIVES TO INVEST

In light of the fact that methane controls have been shown to be profitable, a commonly asked question is: "Why doesn't the O&G industry voluntarily invest in methane emission control?"

In some limited cases, site-specific factors, such as flow rate, temperature, and low gas pressure, make methane emissions control technically infeasible or unprofitable. However, for most of the methane control technologies highlighted in this report, it is simply a matter of modernizing outmoded business practices, commanding resource and budget allocations, and instilling a corporate commitment to greenhouse gas emission reduction.

The American Petroleum Institute (API) explains that in order to maximize profit and provide shareholders with the highest possible return on investment, the O&G industry operates with a strict ranking of capital projects for maximum yield.[12] Thus, even though methane control can be profitable, other core business projects with an even higher rate of return often compete successfully for available corporate funding. Payout periods for methane control technologies discussed in this report range from immediate to three years, yet this may not be attractive enough to compare with oil and gas companies' high expected rates of return. In other cases, factors such as reserves booking (accounting for oil and assets on the balance sheet), and short- and long-term acquisition and divestment strategies can outweigh even high return, low capital methane reduction projects.

Obstacles to implementing even profitable methane control technologies—whether site-specific, financial, or institutional arising from company culture—may seem hard to overcome. But there is an especially compelling case for fixing market failures where limiting greenhouse gas emissions and profits go hand in hand. This is why NRDC finds that where companies do not adopt these technologies voluntarily, regulations requiring mandatory reductions should be implemented. For companies that lack the technical expertise or staff resources in house, there are excellent private and federal resources for technical assistance on methane control.

2.2 METHANE EMISSION TRACKING

In its 2011 *Greenhouse Gas Inventory*, the EPA estimated that the O&G sector emitted 623 Bcf of methane, with natural gas systems accounting for 547 Bcf and liquid petroleum systems contributing 76 Bcf. The EPA also estimated that the industry captured 168 Bcf of gross methane emissions in 2009, exclusively from natural gas systems.[13] If no reductions were implemented, the gross leak rate would be an estimated 791 Bcf/year (623 Bcf/year net emissions plus 168 Bcf/year) as shown in Figure 5. The United States produces approximately 26,000 Bcf of natural gas per year. Thus, at the gross leak rate of 791 Bcf/year, the U.S. O&G industry is losing 3 percent of its total gas production to the atmosphere. At the EPA's net leak rate of 623 Bcf/year , the industry is losing 2.4 percent of its total gas to the atmosphere.

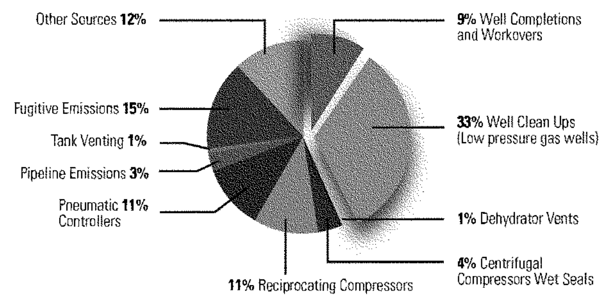
As discussed in Section 2.3 below, the EPA numbers are quite uncertain. Other sources indicate that the amount of methane lost to the atmosphere each year in the United States could be substantially higher.[14]

According to the 2011 *Greenhouse Gas Inventory*, industry achieved the 168 Bcf in reductions through a combination of the EPA's successful voluntary emission reduction program, Natural Gas STAR (77 percent), and federal emission regulations imposed on industry in the past decade to curb emissions (23 percent). The EPA did not identify any emission reductions achieved in the petroleum systems category. Most oil production operations also produce associated gas. Based on EPA estimates, there is a 76 Bcf methane reduction opportunity for the petroleum systems category.

The 2011 *Greenhouse Gas Inventory* tracks methane emissions by leakage source for natural gas systems (Figure 6) and liquid petroleum systems (Figure 7). In natural gas systems, methane emissions primarily come from wells, pneumatic controllers, compressors, and fugitive emissions. In liquid petroleum systems, methane emissions primarily come from equipment leaks, pneumatic controllers, and tank venting. Table 2 shows natural gas and liquid petroleum methane emissions in Bcf and identifies the applicable methane control technologies covered in this report.

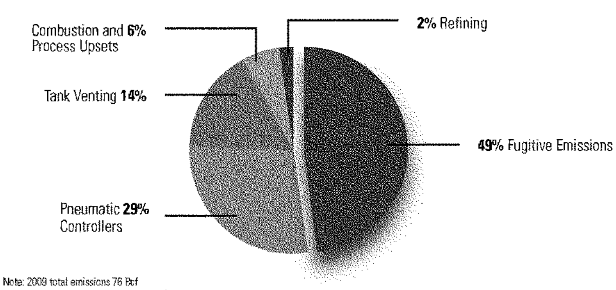
A detailed breakdown of the methane emissions from both natural gas and liquid petroleum systems by source is shown in Appendix C.

Figure 6: Natural Gas System Methane Emission Sources



Note: 2009 total emissions 715 Bcf
Source: U.S. EPA 2011 *Greenhouse Gas Inventory*

Figure 7: Liquid Petroleum System Methane Emission Sources



Note: 2009 total emissions 76 Bcf
Source: U.S. EPA 2011 *Greenhouse Gas Inventory*

Table 2: Methane Emission Sources and Control Technologies

2009 Natural Gas Systems		% of Total	Control Technologies
	Bcf	%	
Well Completions and Workovers	68	9%	No. 1 Green Completions
Well Clean Ups (Low pressure gas wells)	237	33%	No. 1 & 2 Green Completions & Plunger Lift Systems or Other Deliquification Methods
Dehydrator Vents	8	1%	No. 3 & 4 Dehydrator Controls
Centrifugal Compressors Wet Seals	27	4%	No. 5 Dry Seal Systems
Reciprocating Compressors	75	11%	No. 6 Improved Compressor Maintenance
Pneumatic Controllers	77	11%	No. 7 Low -Bleed or No-Bleed Controllers
Pipeline Emissions	19	3%	No. 8 Pipeline Maintenance and Repair
Tank Venting	10	1%	No. 9 Vapor Recovery Units
Fugitive Emissions	106	15%	No. 10 Leak Monitoring and Repair
Total of Emissions Controllable by the 10 Technologies	627	88%	
Other Sources	88	12%	
Total Emissions - Natural Gas	**715**	**100%**	
2009 Liquid Petroleum Systems		**% of Total**	**Control Technologies**
	Bcf	%	
Pneumatic Controllers	22	29%	No. 7 Low-Bleed or No-Bleed Controllers
Tank Venting	11	14%	No. 9 Vapor Recovery Units
Fugitive Emissions	37	49%	No. 10 Leak Monitoring and Repair
Total of Emissions Controllable by the 10 Technologies	70	92%	
Other Sources	6	8%	
Total Emissions - Liquid Petroleum	**76**	**100%**	

Source: U.S. Environmental Protection Agency Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009.

2.3 UNCERTAINTY IN EMISSION ESTIMATES

The EPA has been tracking methane emissions since 1990. For more than 20 years, significant uncertainty has accompanied estimates of emissions from the O&G industry, with a general theme of underestimation. Some emissions have been underestimated by and for the O&G industry because sources have not been metered or tested to accurately determine the emission rate. Small emission sources that may result in cumulatively large emission totals have escaped emission monitoring or reporting, and not all emission sources are accounted for.

Evidence for underestimation due to uncertainty is found in the 2010 *Greenhouse Gas Inventory*, which states that "[n]atural gas well venting due to unconventional well completions and workovers, as well as conventional gas well blowdowns to unload liquids have already been identified as sources for which Natural Gas STAR reported reductions are significantly larger than the estimated inventory emissions."[15]

Historically, the *Greenhouse Gas Inventory* was based on an emission factor of approximately 3,000 standard cubic feet (3 Mcf) per gas well drilled and completed.[16] Yet Natural Gas STAR program partner experience shows several cases where emission factors were thousands of times higher:

- BP employed green completions at 106 wells and reported 3,300 Mcf of gas recovered per well[17]
- Devon Barnett Shale employed green completions at 1,798 wells between 2005 and 2008 and reported 6,300 Mcf of gas recovery per well[18]
- Williams employed green completions at 1,064 wells in the Piceance Basin and reported 23,000 Mcf of gas recovered per well[19]

All of these examples show gas recovery estimates more than 1,000 times higher than the 3 Mcf of gas per well estimated in the 2008 *Greenhouse Gas Inventory*.[20] Clearly, errors in emission inventory estimations have occurred.

Well completion emission estimates were underestimated by a factor of 1,000

The source of much of this uncertainty regarding well venting is the EPA's historic reliance on a 1997 study jointly funded with the Gas Research Institute (GRI) to quantify methane emissions from United States natural gas operations.[21] The study concluded that methane emitted (leaked and vented) from natural gas facilities at an amount of 1.4 percent +/- 0.5 percent (approximately 1 to 2 percent) of gross natural gas production, and that additional emission controls could significantly reduce the amount of methane gas leaked and vented to atmosphere.

However, the study did not include important equipment leaks and venting that took place at the wellhead or at the well pad processing facilities in natural gas systems.

The largest change in methane emission estimates has been in accounting for wellhead and well pad processing facilities emissions that were substantially underestimated. Since 1990, the EPA has more than doubled its methane emission estimate for natural gas systems from 220 Bcf to 464 Bcf. For many years the EPA quoted a 300 to 400 Bcf/year methane emission estimate for the entire O&G industry, yet now the EPA reports a 322 to 464 Bcf range for natural gas production alone (Figure 8). While some of the methane emission increase is attributed to growth in natural gas production, most of the increase represents continuous improvement in and revisions to the EPA's emission estimates as it furthers its understanding of methane emissions sources from the O&G industry. For instance, in past years emissions arising from poor connections from the wellhead to processing equipment to transmission equipment were overlooked. Low emissions from the distribution stage as a result of low-leakage welded joints may have contributed to a misconception that equipment upstream of the distribution stage was also similarly leak-free.

In 2010, the EPA undertook to develop a set of greenhouse gas reporting requirements for the O&G industry as part of a general charge from Congress to develop greenhouse gas reporting rules for all U.S. industries. The EPA assessed uncertainty in O&G emission estimates during this undertaking. The EPA explained the historic underestimation of natural gas systems, critiquing the "outdated and potentially understated" emissions estimates from the 1997 report.[22] The EPA cited several significant sources of underestimated emissions:

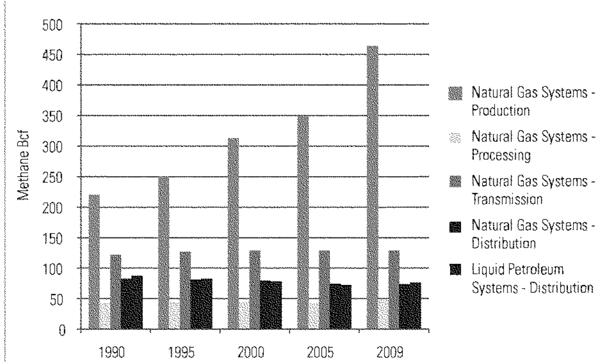
> *The following emissions sources are believed to be significantly underestimated in the United States GHG Inventory: well venting for liquids unloading; gas well venting during well completions; gas well venting during well workovers; crude oil and condensate storage tanks; centrifugal compressor wet seal degassing venting; and flaring.*

In its 2011 *Greenhouse Gas Inventory*, the EPA raised its gross emissions estimate to 791 Bcf/year by adding the amount of gas that may be vented at the wellhead to the amount of gas that leaks from the processing equipment and pipeline infrastructure once the gas enters the system.

According to the EPA's O&G Reporting Rule Technical Support Document, the emissions estimates for these sources "do not correctly reflect the operational practices of today." In fact, the EPA believes that "emissions from some sources may be much higher than currently reported in the United States GHG Inventory."[23]

The EPA revised emissions factors for four of these underestimated sources. Revised emissions estimates range from 11 times higher for well venting from liquids unloading, to 36 times higher for gas well venting from conventional well completions, to 3,540 and 8,800 times higher for gas well venting during well workovers and completions of unconventional wells, respectively.[24] Even with the EPA's revisions to the O&G Reporting Rule, uncertainty continues to exist in the estimates of emissions from gas well completions and well workovers. As the EPA noted in the preamble to its proposed reporting rule:

Figure 8: O&G Industry Methane Emissions 1990 to 2009



Source: U.S. EPA 2011 *Greenhouse Gas Inventory*

> *"[N]o body of data has been identified that can be summarized into generally applicable emissions factors to characterize emissions from these sources [(i.e., from well completion venting and well workover venting)] in each unique field. In fact, the emissions factor being used in the 2008 U.S. GHG Inventory is believed to significantly underestimate emissions based on industry experience as included in the EPA Natural Gas STAR Program publicly available information (http://www.epa.gov/gasstar/). In addition, the 2008 U.S. GHG Inventory emissions factor was developed prior to the boom in unconventional well drilling (1992) and in the absence of any field data and does not capture the diversity of well completion and workover operations or the variance in emissions that can be expected from different hydrocarbon reservoirs in the country."*[25]

The EPA continues to report substantial uncertainty in its overall greenhouse gas emission estimates in its ongoing work on the *Greenhouse Gas Inventory*,[26] with uncertainty particularly evident for natural gas systems. In its 2011 *Greenhouse Gas Inventory*, the EPA used an average emission factor of 7,700 Mcf per well completion—much higher than its previous emissions factor of 3,000 Mcf per well completion—more than doubling the amount of emissions expected from the increasing number of unconventional well completions (e.g. horizontal and shale gas wells). Furthermore, the EPA did not include emissions from completions for tight gas wells in the 2011 *Greenhouse Gas Inventory*, which, as the EPA noted previously in its O&G Reporting Rule Technical Support Document, is a "significant underestimate" of total emissions.[27] The EPA also reported zero emissions from well completions in the Northeast region, which is the location of extensive shale gas drilling and well completions in the Marcellus Shale.

Emissions estimates will likely continue to evolve and improve as the EPA obtains additional information from the O&G industry, including information submitted under its mandatory reporting rule. As with past inventories, it is expected that both emissions factors and activity factors will continue to be updated. If past trends hold, these factors are likely to be revised upward as a result of both better understanding of emissions associated with each process, and the aggressive pace of drilling and development across the country. However, emissions estimates for an individual source may also be revised downward as the EPA obtains better information about the type and amount of control technology in use.

Incidentally, the United States is not the only country that has struggled with estimating the O&G industry's greenhouse gas emissions. Canada reports that its natural gas processing plants also discovered that methane emissions were roughly an order of magnitude higher than estimated.[28]

Despite all the uncertainty about the precise amount of methane emissions, we do know that there is a significant amount of methane that is leaking or being vented into the atmosphere that could be captured and sold or used as fuel.

2.4 VOLUNTARY CONTROL WITH EPA NATURAL GAS STAR

For a number of years, the EPA has coordinated the Natural Gas STAR Program, which describes itself as a "flexible, voluntary partnership that encourages oil and natural gas companies—both domestically and abroad—to adopt cost-effective technologies and practices that improve operational efficiency and reduce emissions of methane, a potent greenhouse gas and an important transitional energy source."[29]

To its credit, the EPA actively encourages O&G operators to invest in methane reduction technology through its Natural Gas STAR Program. Those members of the O&G industry that have recognized the adverse economic and environmental implications of methane emissions, and have voluntarily invested in greenhouse gas emission reduction technology at their facilities, also deserve credit.

While the Natural Gas STAR Program has been successful in identifying and documenting profitable methane emission reduction opportunities that aid in methane capture and in bringing captured methane into the revenue stream, to date the program remains voluntary and participation is limited.

Companies that participate in Natural Gas STAR sign a Memorandum of Understanding with the EPA, then evaluate and implement identified methane emission reduction opportunities. Companies can participate at any level they choose, from company-wide to site-specific to small pilot projects.[30] There is no mandatory requirement to identify or implement all methane reduction opportunities.

The extent to which enrolled companies participate is difficult to confirm. Natural Gas STAR publishes a list of participating companies, but all reports on the actual locations of emission control implementation, which methane control measures have been implemented by each company, and the emission reductions achieved, are confidential.

Despite these demonstrated solutions for capturing methane, many companies still have not participated in the Natural Gas STAR Program at all, and others have only implemented a few methane control measures.[31] Effective as the EPA's Natural Gas STAR efforts have been, vast quantities of methane continue to leak into the atmosphere. It is therefore clear that voluntary measures alone will not ensure that industry installs even profitable capture technologies.

2.5 PROPOSED EPA RULES NOT STRONG ENOUGH

On August 23rd 2011, the EPA published proposed regulations for a suite of technologies to reduce harmful air pollution from the oil and natural gas industry.[32] The rules are to be finalized by April 2012, after an opportunity for public comment.

The proposed EPA rules include NSPS for source categories as well as air toxics standards, or NESHAPs. In particular, the EPA is proposing stringent new NSPS for controls for VOCs from the oil and gas sector, which will also capture significant amounts of methane (referred to as "co-benefits" of the regulation).

The EPA estimates that the proposed NSPS for VOCs would reduce 540,000 tons of VOCs, an industry-wide reduction of 25 percent. The air toxics standards would reduce air toxics emissions by 30,000 tons, an overall reduction of nearly 30 percent.[33] The EPA estimates that the proposed standards would also reduce about 3.4 million tons per year of methane. This equates to roughly 160 Bcf/year. As an interim measure, the EPA quantified the global social benefits of these methane reductions in mitigating climate change at up to $4.7 billion in 2015 co-benefits. For reasons set forth in NRDC's comments to the EPA on the proposed NSPS, we believe even this figure is a substantial underestimation.

Finally, the emissions baseline used in the EPA's proposed NSPS differs somewhat from the 791 Bcf/year gross emissions baseline in this report derived from the EPA's 2011 *Greenhouse Gas Inventory*. The differences reflect, among other things, the evolving nature of the emissions inventory. However, the differences do not meaningfully alter the analysis and recommendations made in this report.

The EPA's proposed standards do not control methane directly or cover existing sources, which account for the bulk of VOC and methane emissions. Further, the EPA omits other significant sources of VOCs and methane, in part due to exclusion of these sources altogether and in part because methane is not directly regulated. These omissions contrast with areas where the NSPS would in fact more effectively control emissions, such as from well completions and recompletions, and new sources of emission from pneumatic controllers, compressors, and equipment leaks.

This report does not provide a comprehensive assessment of the proposed NSPS, but the control technologies described here can serve as a guide to the EPA and the states in their control efforts.

Methane emissions reductions should be a high priority, as they provide economic, health, safety, and environmental benefits for both operators and the public. Existing market forces, government regulations, and voluntary programs are only leading to the capture of a small percentage of methane emissions at present. The EPA's proposed NSPS is a step in the right direction.

3. ANALYTIC APPROACH

While it would have been useful for the EPA to report the 168 Bcf emission reductions by leakage source, to clarify which sources and associated emissions reduction technologies are making progress in reducing emissions, that level of detail is not necessary to analyze the data and describe in layman's terms why methane control technologies are profitable and point out large potential methane control opportunities.

Since the EPA does not provide sufficient data in its inventory to break down the emission reductions by natural gas leakage source, the methane emission estimates used in this report correspond to EPA's emission estimate of 791 Bcf for natural gas and liquid petroleum systems.

This 791 Bcf estimate of gross emissions from both natural gas (715 Bcf) and petroleum (76 Bcf) systems has been reduced, the EPA reports, by 168 Bcf from Natural Gas STAR programs and regulations. All of these reductions have been achieved in natural gas systems. The total net emissions from both systems is therefore 623 Bcf (791 Bcf less 168 Bcf). The total net emissions from natural gas systems is 547 Bcf (715 Bcf less 168 Bcf), and from petroleum systems it is 76 Bcf (Table 3). Additionally, it is important to note that the EPA's Natural Gas STAR Program emission reduction estimates are based on data voluntarily submitted by industry. These data represent a very rough estimate of the amount of methane control that may have been achieved to date, because they were not developed using common and rigorous metering, measurement, quality control, or audit procedures. Therefore, some caution should be exercised in assuming that this amount of emissions reduction has been fully achieved.

Table 3: Methane Emission Control Opportunity

2009 Natural Gas Systems			Natural Gas STAR Reductions	EPA Regulation Reductions	Total Reductions	Estimated Remaining Target
	Gg	Bcf	Bcf	Bcf	Bcf	Bcf
Production	8,931	464	104	38	142	322
Processing	931	48	4	1	5	43
Transmission	2,482	129	19	0	19	110
Distribution	1,422	74	2	0	2	72
Total	**13,766**	**715**	**129**	**39**	**168**	**547**
2009 Liquid Petroleum Systems						
Production	1,444	75	0	0	0	75
Transmission	5	0	0	0	0	0
Refining	24	1	0	0	0	1
Total	**1,473**	**76**	**0**	**0**	**0**	**76**

Source: U.S. EPA 2011 *Greenhouse Gas Inventory*
*Slight rounding error accumulated in EPA tables. EPA records 715 Bcf and 168 Bcf as final estimates for 2009. Conversion: Gg/19.26=Bcf

3.1 PROFITABILITY

Profitable emission control opportunity, for purposes of this report, means an investment in methane emission control technology that results in more revenue generated or costs offset than the cost to install, operate, and maintain the emission control technology. To assist in identification of such opportunities, this analysis used the following criteria:

1. Control technology that either allows methane to be captured and placed into a natural gas pipeline for sale, or captured and used as fuel to offset operating cost
2. Technology that is commercially available, meaning that it has been developed, tested, and is available in the market for purchase and installation
3. Technology that has been used successfully in actual O&G operations
4. Emission control solutions that are well documented and reported by the O&G industry as profitable

The analysis recognizes that some emission reduction measures can be implemented quickly, while others may require more extensive planning, procurement, and execution timing.

Most of the emission control technologies described in this report have a very short payout period of a few months or years. The term "payout" means the period of time that it takes for the net cash flow to equal the investment expenditure, at which point the investment breaks even and starts to generate positive cash flow, as shown in Figure 9.[34] The revenue stream is calculated using constant dollars over the payout period.[35]

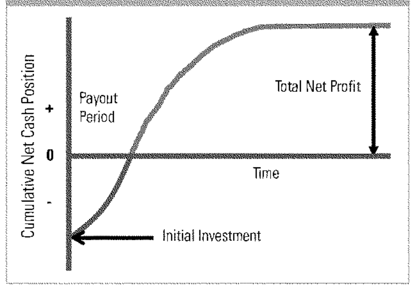
3.2 EXAMINATION OF METHANE CONTROL OPTIONS

Each of the 10 methane control options examined in this report is considered with a six-part analysis.

1. **Technology Description.** The technology description section identifies the equipment required and processes used in each control technology to capture methane emissions.
2. **Opportunity.** The opportunity section identifies the gross amount of methane emissions in the 2011 *Greenhouse Gas Inventory* that could be captured by each control technology for its associated leakage source.

   This estimate of potential emissions reductions assumes nearly complete technical feasibility for all sources in a category, and sufficient time for the deployment of these technologies industry-wide. A detailed analysis of the technical feasibility of technology deployment is beyond the scope of this report. As such, the per-unit emission estimates provided in the opportunity section of the report are intended to provide an average emission control number, to use as a starting basis in a feasibility assessment. Individual consideration may be appropriate based on unique or exceptional circumstances at each site.

Figure 9: Payout Period Diagram



3. **EPA Proposed Regulations.** This section analyzes the proposed regulations from the EPA that are relevant to emissions from each source. It also discusses the emission reductions anticipated from the proposed EPA regulations, and concludes with a description of possible shortcomings of and improvements to the EPA proposal.
4. **Profit.** The profit section analyzes the costs of implementing each technology, along with any associated operational savings and revenues from methane sales. The revenues are calculated by multiplying the amount of methane controlled by a price of $4/Mcf. The report does not attempt to quantify the additional financial benefits from offsetting fuel costs. Comparing the costs with the savings and additional revenues provides the profit. The average payout period is also calculated using these numbers. The cost data are intended to provide an average cost to use as a starting basis in a feasibility assessment. Again, individual consideration may be appropriate based on the particulars of a given application.

   The proposed EPA regulations provide some estimates of the profitability of the various control technologies. However, in the supporting documentation for the proposed rulemaking, the EPA was not transparent enough about its methodology for cost-benefit estimates.[36] As a result, we were unable to independently verify sources and incorporate them into profitability estimates. Instead, we have relied on estimates from prior EPA and company reports. For the sake of completeness, in the appendix we provide tables of profitability estimates by control technology from this report, and compare them with the EPA estimates from the proposed rulemaking supporting documentation. In general, the EPA's proposed rulemaking estimates are somewhat more conservative than NRDC estimates. A more detailed analysis of NRDC's profitability comparisons can be found in the EPA's rulemaking docket.[37]

5. **Additional Benefits.** Beyond generating revenue, the additional benefits of methane capture for each technology are highlighted in this section.
6. **Limitations and Evaluation.** All emission control options have some technological (and, potentially, economic) limitations, and where those are known, they are summarized in this section for use as a starting point in a feasibility assessment. In some cases, a certain emission control technology may not be suitable because it cannot handle a gas flow rate, temperature, or pressure. In other cases, the technology may not be appropriate for a retrofit, but would be a logical choice for designing and installing a new unit. This section includes flow charts to depict the basic decision steps of a feasibility analysis. The flow charts are intended to be simplistic outlines of the steps that might be taken to determine the feasibility of using a particular emission control method. This simplified approach is not intended to replace any company-specific evaluation processes, but rather to provide a basic outline of the evaluation steps in laymen's terms.

3.3. METHANE EMISSION REPORTING UNITS

While greenhouse gas emission estimates are often reported in terms of million metric tons of carbon dioxide equivalent ($MMtCO_2e$), all methane emission and methane control estimates in this report are shown in terms of standard cubic feet, and most often reported in billions of standard cubic feet (Bcf). The report uses this emission reporting convention because gas is sold and used on a basis of standard cubic feet, and this unit can readily be converted to a profit estimate using a market price assumption of four dollars per thousand standard cubic feet ($4/Mcf). This reporting convention prevents the reader from having to routinely convert from $MMtCO_2e$ to Bcf.

4. TEN PROFITABLE TECHNOLOGIES: AN ANALYSIS

The emission control potential, uses, benefits, and economics of each of the 10 methane control technologies are discussed in greater detail in this chapter. While many of the technologies are profitable on a very short time scale, many operators still have not installed them. In order to realize the methane control potential to limit greenhouse gas emissions, NRDC also proposes policy options to encourage the use of these technologies.

Table 4: Methane Capture Technology Costs and Benefits

Technology	Investment Cost	Methane Capture	Profit	Payout
Green Completions	$8,700 to $33,000 per well	7,000 to 23,000 Mcf/well	$28,000 to $90,000 per well	< 0.5 – 1 year
Plunger Lift Systems	$2,600 to $13,000 per well	600 to 18,250 Mcf/year	$2,000 to $103,000 per year	< 1 year
TEG Dehydrator Emission Controls	Up to $13,000 for 4 controls	3,600 to 35,000 Mcf/year	$14,000 to $138,000 per year	< 0.5 years
Desiccant Dehydrators	$16,000 per device	1,000 Mcf/year	$6,000 per year	< 3 years
Dry Seal Systems	$90,000 to $324,000 per device	18,000 to 100,000 Mcf/year	$280,000 to $520,000 per year	0.5 – 1.5 years
Improved Compressor Maintenance	$1,200 to $1,600 per rod packing	850 Mcf/year per rod packing	$3,500 per year	0.5 years
Pneumatic Controllers Low-Bleed	$175 to $350 per device	125 to 300 Mcf/year	$500 to $1,900 per year	< 0.5 – 1 year
Pneumatic Controllers No-Bleed	$10,000 to $60,000 per device	5,400 to 20,000 Mcf/year	$14,000 to $62,000 per year	< 2 years
Pipeline Maintenance and Repair	Varies widely	Varies widely but significant	Varies widely by significant	< 1 year
Vapor Recovery Units	$36,000 to $104,000 per device	5,000 to 91,000 Mcf/year	$4,000 to $348,000 per year	0.5 – 3 years
Leak Monitoring and Repair	$26,000 to $59,000 per facility	30,000 to 87,000 Mcf/year	$117,000 to $314,000 per facility per year	< 0.5 years

Note: Profit includes revenue from deployment of technology plus any O&M savings or costs, but excludes depreciation. Additional details provided in Appendix A.
Source: NRDC analysis of available industry information. Individual technology information sources cited in Chapter 4.

4.1 GREEN COMPLETIONS

Methane gas is often released into the atmosphere when natural gas or oil wells are drilled, stimulated (e.g. hydraulically fractured), or repaired. Green completions can be used to capture methane gas and gas liquids (condensate).[38] Rather than being vented or flared into the atmosphere, methane captured in a green completion can be sold, used as fuel, or re-injected to improve well performance. Green completions also capture gas liquids that can be sold.

This technology is also called reduced emission completions, or REC, but throughout this report we use the term "green completions."

When a well is drilled and completed, stimulated, or repaired, it is standard procedure to flow the well for a period of time to remove stimulation materials and other debris from the wellbore. This procedure is called "wellbore cleanup" and occurs before connecting the well to permanent processing equipment. Wellbore cleanup allows the operator to remove and dispose of unwanted material without contaminating production facilities and pipelines. It also improves well recovery rates by reducing wellbore formation damage downhole. Historically, wells were "cleaned up" by flowing liquid hydrocarbons to an open pit or tank, and by routing the associated methane gas to a gas vent or flare (Figure 10).

Venting gas near well operations creates potentially explosive vapor levels and can pose a human health hazard. Flaring resolves much of the explosive vapor problem by routing gas away from the well operations to a flare stack that burns the gas at a distance from the well and associated facilities, but flaring creates economic waste by combusting gas that could otherwise be collected and sold. Flaring also varies in efficiency, so not all pollutants may be combusted, and also generates air, light, and noise pollution.

4.1.1 Technology Description

In a green completion, the operator brings temporary processing equipment to a well site during wellbore cleanup. Well cleanup fluids and gases are routed to the temporary processing equipment. Fluids, debris, and gas are separated, and gas and condensate are recovered for sale. The temporary processing equipment required for a green completion typically includes gas-liquid-sand separator traps, portable separators, portable gas dehydration units, additional tanks, and, sometimes, small compressors. A simplified schematic showing the equipment required for a green completion is shown in Figure 11.

Green completion processing equipment, which provides temporary gas processing capability, is typically mounted on a truck or trailer to move it from well to well (Figure 12).

Figure 10: Gas Well Flaring

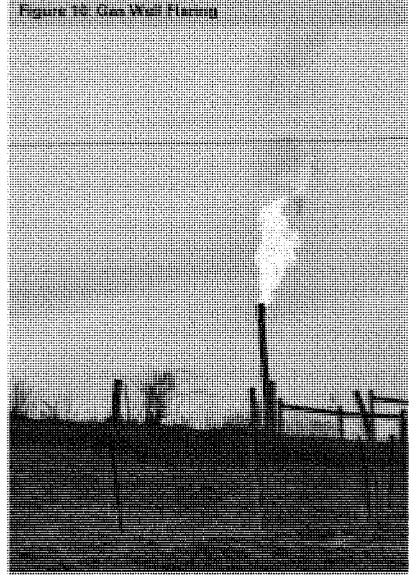


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Figure 11: Green Completion Equipment Schematic

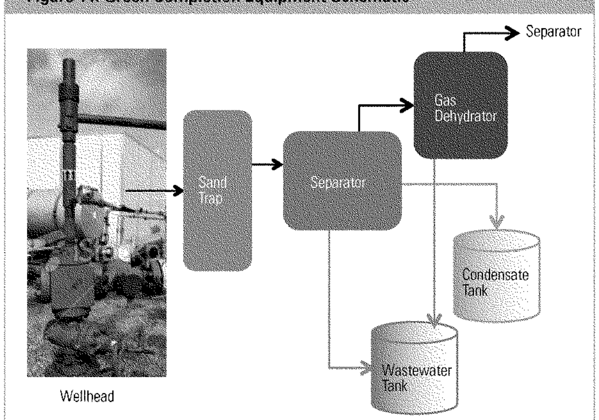
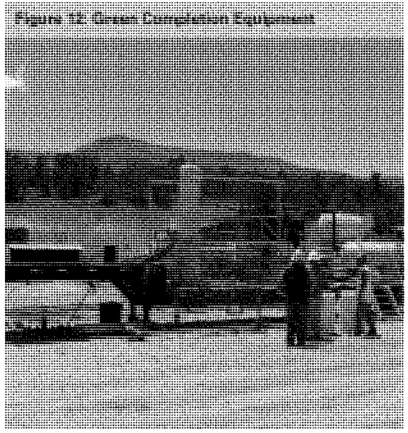


Figure 12: Green Completion Equipment



Colorado Oil & Gas Conservation Commission, "Proposed Rules for Green Completions" presentation June 27, 2008

Portable green completion units are either owned by the operator or rented from a service provider. For new wells, equipment may need to be brought to the well site to provide temporary gas processing capability. However, at existing well sites, where wells have already been drilled but may need to be repaired or stimulated to improve hydrocarbon production rates, gas processing equipment may already be available onsite.

While the processing equipment is portable, some permanent facility infrastructure must be in place at the well site to make a green completion possible. Gas collected from a green completion can be used in several ways. It can be sold in a pipeline, used as fuel at the well site, or used as gas lift to enhance hydrocarbon production in low pressure wells. Each of these uses requires piping infrastructure to be in place at the well site to route the gas to the appropriate destination. Therefore, a green completion is typically not an option for exploration wells with no offset wells or pipeline infrastructure nearby.

The EPA estimates that an average of 8,200 Mcf can be recovered per green completion

Typically, gas produced from a well contains liquid ("wet gas") that exceeds tbe acceptable moisture content allowed in a gas sales pipeline. Depending on the gas composition, hydrocarbons may also condense from a gas to a liquid under certain temperature and pressure conditions. The pressure drop from the wellhead through the gas processing equipment can also yield gas-liquids (condensate) that can be captured and sold. Therefore, in most cases, before gas from a green completion can be routed to a gas sales pipeline, it must be dehydrated to remove liquids to meet the gas pipeline specifications. Gas dehydration can be accomplished by bringing in a portable gas dehydration unit, or using a permanent gas dehydrator installed upstream of a gas pipeline. Condensate can either be collected in a temporary stock tank, or routed to a permanent stock tank if one is located on site.

4.1.2 Opportunity

Reduction Target: 68 Bcf/year and a portion of 237 Bcf/year

The 2011 *Greenhouse Gas Inventory* estimates that well completions, workovers, and well cleanups emit approximately 305 Bcf of methane annually, 43 percent of total natural gas systems methane emissions.[39] Of this amount, well completions and workovers contributed about 68 Bcf/year, and well cleanups contributed about 237 Bcf/year, as shown in Table 2. Green completions may be used to control a significant fraction of emissions from well completions and workovers. Green completions can also be used to control a portion of the emissions from well cleanups, also known as liquids unloading.

There remains considerable uncertainty in wellhead emissions. In the decade prior to the 2011 *Greenhouse Gas Inventory*, the EPA revised its well emission estimates upward several times, and it reports continued uncertainty in the 2011 inventory estimates. It is likely that well methane emissions are still underestimated.

Green completions alone could enable the United States to achieve more than 30 percent of its O&G industry methane reduction opportunity

In 2005, the EPA estimated that an average of 7,000 Mcf of natural gas can be recovered during each green completion.[40] In 2011, the EPA increased its reduction estimate to 8,200 Mcf per green completion.[41] As part of its analyses relating to Subpart W of the Greenhouse Gas Reporting Rule, the EPA calculated the average emissions reduction to be 9,175 Mcf per green completion.[42] In a 2011 *Lessons Learned* report, the EPA estimated that an average of 10,800 Mcf could be saved per green completion.[43]

The EPA has found that green completions can be a major contributor to methane reductions on a national scale. In 2008, the EPA's Natural Gas STAR Program attributed 50 percent of the program's total reductions for the O&G production sector to green completions.[44] Considering the promising technical and economic feasibility of green completions, a very large fraction of tbe emissions from well completions and workovers, and a portion of the emissions from well cleanups, could be captured using green completions.

The commercial viability of green completion equipment has been so well demonstrated that it is now required in several states:

- Colorado requires green completions on all oil and gas wells unless it is not technically and economically feasible.[45]
- Fort Worth, Texas requires green completions for all wells that have a sales line nearby, and for wells that are shut-in while gas is conserved, unless the operator can show that this requirement would endanger the safety of personnel or the public.[46]
- Montana requires VOC vapors (including methane) greater than 500 British Thermal Units (BTUs) per cubic foot from wellhead equipment with the potential to emit 15 tons per year or greater, to be routed to a control device (such as a flare), or to a pipeline for sale.[47]
- Wyoming has required green completions in the Jonah-Pinedale Anticline Development Area (JPAD) since 2007. More recently, Wyoming has expanded this requirement to all Concentrated Development Areas of oil and gas in the state.[48]

Such rules mandating green completions are an excellent method to help reduce emissions of greenhouse gases and toxic air pollutants, and exceptions written into these rules allowing operators not to use green completion technology should be very narrow, limited to only when it is proven to be unsafe or technically infeasible.

The API reports that there are only 300 green completion units in operation in the United States with the ability to complete 4,000 wells per year.[49] This corroborates the upper end of the EPA's estimate that the U.S. O&G industry has a capacity to implement approximately 3,000 to 4,000 green completions per year.[50]

While some operators report use of green completions at a portion of their operations in the United States, it is clear that opportunities abound for much wider deployment of green completions to reduce methane emissions. The API estimates that only 20 percent of U.S. gas well emissions are currently being captured by green completions and that an additional 16,000 wells per year could be processed if there were sufficient green completion equipment capacity.

4.1.3 Proposed EPA Regulations

The EPA is proposing to require green completions to control emissions from all production wells that undergo a hydraulic fracture treatment. The EPA proposes to exempt exploration wells and all other gas wells that are not hydraulically fractured.

Therefore, the EPA expects that more than 95 percent of emissions from well completions and workovers would be controlled using green completions. NRDC applauds the EPA's proposed regulations for targeting significant emissions reductions during well completions and recompletions. Still, green completions should be required for all wells where technically feasible, including well cleanups and wells that are not hydraulically fractured. Such a requirement can be expected to lead to the rapid increase in availability of green completion equipment.

4.1.4 Profit

Green completions provide an immediate revenue stream by routing to a gas sales line gas (methane and condensates) which would otherwise be vented into the atmosphere or flared. Alternatively, captured gas can be used for fuel, offsetting operating costs or be re-injected to improve well performance. Industry has demonstrated that green completions are both an environmental best practice and profitable.

For each unconventional gas well green completion, there is an opportunity to generate about $28,000 to $90,000 in profit, based on capture rates of 7,000 to 23,000 Mcf per well, as shown in additional detail in Appendix A, Table A1. The EPA currently estimates the cost of implementing a green completion as high as $33,000 (for rented equipment).[51,52] Based on these and other estimates, green completions using rented equipment will typically pay out immediately while those with purchased equipment will pay out within a year.[53] NRDC recognizes wells currently chosen for green completions are likely to be more productive and therefore profitable than average wells going forward.

Operators with a sufficient number of wells to amortize the cost of the equipment are finding it economically attractive to invest in their own green completion technology rather than to rent equipment. Most companies that have gone this route report a one- to- two year payout for investment in purchasing green completion equipment, and substantial profitability thereafter.[54]

Smaller operators can rent green completion equipment from a contractor. Renting equipment will result in a lower profit margin because there is usually a slightly higher operating cost attributed to equipment rental versus equipment ownership. Still, the payout for this investment would occur quickly if a contractor was hired and the operator paid only a per well green completion equipment rental charge. As long as the gas captured and sold exceeded the equipment rental charge, payout would be immediate.

In a 2009 study conducted for New York State, ICF Incorporated found that equipment payouts may be as short as three months. ICF also found that companies electing to conduct green completions in 2005 made more than $65 million in profits.[55]

Examples listed below demonstrate bow profitable green completions can be. The data is provided in the form reported by each company. However, these examples show that green completions are profitable, and generally pay out in less than two years:

- In 2004, Devon Energy reported an average incremental cost to perform a green completion of $8,700 per well at its Texas Fort Worth Basin operations. Devon estimated that it made a profit of $50,000 per well by selling the captured gas to market and achieved a total emission reduction of 6.16 Bcf at its operations in year 2005. 78 percent of the methane captured (4.8 Bcf) was attributed to green completion methods.[56,57]
- BP reported an initial investment cost of $1.4 million to purchase a portable three-phase separator, sand trap, and tanks to conduct green completions. By 2005, BP completed 106 wells using this equipment and reported an average gas recovery of 0.35 Bcf per year, and condensate recovery of 6,700 barrels per year. The company's investment paid out in less than two years. Thereafter, the equipment brought in a profit of at least $840,000 per year.[58] In 2007, BP reported that green completions had netted a profit of $3.4 million on an investment of $1.2 million, with a payout of 0.7 years, and a capture of 130 Mt of methane per well.[59]
- Williams reported $159 million in revenue from green completions in its Colorado Piceance Basin Operations from 2002 to 2006, on an investment of $17 million, for a net profit of $142 million.[60] Williams' data was based on 1,177 wells and an average gas recovery of approximately 91 percent.
- EnCana Corporation, the largest natural gas producer in North America, which produces 1.5 percent of United States daily gas needs, reported that green completion methods were extremely profitable in the Jonah Field in Wyoming, yielding a net present value (NPV) of more than $190 million.[61] EnCana's initial investment in the portable green completion equipment for the Jonah Field paid out in the first year.
- Anadarko reported an increased operating profit of $10.3 million per year for the period 2006 to 2008 due to green completions on an average of 613 wells per year.[62]

4.1.5 Additional Benefits

Green completions provide a number of additional benefits, aside from profitability and methane emission reductions. Green completions:

- Collect potentially explosive gas vapors, rather than venting them into the atmosphere (improves well site safety, reduces worker exposure to harmful vapors, and limits overall corporate liability)
- Reduce or eliminate the need for flaring
- Reduce emissions, noises, odors, and citizen complaints associated with venting or flaring
- Reduce VOCs and HAPs contained in natural gas along with methane. If flared and not captured, VOCs and HAPs generate nitrogen oxides (NO_x) and particulate matter (PM), contributors to ground-level ozone and regional haze
- Improve well cleanup and enhance well productivity, as wells flow back to portable separation units for longer periods than would be allowed with direct venting into the atmosphere or flaring
- Reduce the need to drill new wells as more methane is kept in the system and brought to market

4.1.6 Limitations and Evaluation

Green completions are most successful and profitable on higher pressure wells that have sufficient gas reservoir pressure to both flow into a pressurized gas sales pipeline and adequately clean up the wellbore.[63]

For lower pressure wells, artificial lift may be required, using portable compressors to withdraw gas from a pressurized sales gas line. The pressurized gas is then injected into the well to unload wellbore liquids and solids (artificial lift), and initiate flow. Compressors may also be needed to boost the lower pressure gas back into the sales line until normal reservoir flow and pressure is established.[64] Adding compression to the equipment package required for a green completion will increase cost.

Recognizing the existence of technical limits, Colorado sets boundaries on when green completions should be required:

> *"Green completion practices are required on oil and gas wells where reservoir pressure, formation productivity, and wellbore conditions are likely to enable the well to be capable of naturally flowing hydrocarbon gas in flammable or greater concentrations at a stabilized rate in excess of five hundred (500) MCFD to the surface against an induced surface backpressure of five hundred (500) psig or sales line pressure, whichever is greater. Green completion practices are not required for exploratory wells, where the wells are not sufficiently proximate to sales lines, or where green completion practices are otherwise not technically and economically feasible.*
>
> *An operator may request a variance from the Director if it believes that employing green completion practices is not feasible because of well or field conditions or that following them in a specific instance would endanger the safety of well site personnel or the public."*[65]

In the event that Colorado issues a variance from using green completion techniques due to technical or safety constraints, it still requires the use of Best Management Practices to minimize the amount of methane emitted:

> *"In instances where green completion practices are not technically feasible or are not required, operators shall employ Best Management Practices to reduce emissions. Such BMPs may include measures or actions, considering safety, to minimize the time period during which gases are emitted directly to the atmosphere, or monitoring and recording the volume and time period of such emissions."*

Because pipelines are typically not installed at a natural gas production site until it is confirmed that an economical gas supply is found, gas from the first well is often flared or vented during drilling and completion activities. However, once a pipeline is installed, subsequent wells drilled on that same pad would be in a position to implement green completion techniques. Operators often point to the lack of pipeline infrastructure as a primary reason a green completion may not be possible, in particular at oil production facilities that do not have a nearby gas sales line. However, there are also alternatives to piping methane, such as using it on-site to generate power, re-injecting it to improve well performance, or providing it to local residents as an affordable power supply.

Figure 13 provides a simplified flowchart showing the basic steps for evaluating whether a green completion is technically feasible and profitable.

4.2 PLUNGER LIFT SYSTEMS

Older gas wells stop flowing when liquids (water and condensate) accumulate inside the wellbore. As liquid builds up in the wellbore it creates backpressure on the hydrocarbon formation, further reducing the gas flow rate.

Methane gas is emitted when companies open wells to vent gas to the atmosphere to unload wellbore liquids (water and condensate that accumulate in the bottom of the well) in order to resume gas flow. The industry typically refers to this process as "blowing down the well," a "well blowdown," or a "well deliquification."

Eventually, even a well's own gas pressure becomes insufficient to flow accumulated liquids to the surface and the well is either sbut-in as uneconomic, or some form of artificial lift is installed to transport the liquids to the surface.

Plunger lift systems are one method of lifting accumulated liquids in the wellbore to the surface. In this method, methane gas can be captured and sold, rather than vented to atmosphere as waste.

4.2.1 Technology Description

Installation of plunger lift systems provides an immediate revenue stream by routing methane gas to a gas sales line that would otherwise be vented. Industry has demonstrated that plunger lift systems are both an environmental best practice and profitable when addressing mature gas wells with back pressure from liquids.

Accumulation of liquid hydrocarbons and liquids in the well tubing of mature gas wells can halt or impede gas production. Historically, well operators would vent these mature gas wells to atmosphere to aid in expelling the liquids from the well tubing. Alternatively, plunger lift systems can be installed in a well to lift the liquids out of the well (Figure 14).

There are a number of deliquification methods that can be used on a mature gas well singly or in combination, such as sucker rod pumps, electric submersible pumps, progressing cavity pumps, compression, swabbing, gas lift, and smaller diameter tubing (velocity strings), but most of these methods require the addition of energy.[66] The plunger lift system is a low-cost system that uses the well's own natural energy to complete the deliquification process. This technology is particularly useful at well sites that do not have power.

Plunger lift systems work by using the natural gas pressure that builds up in the casing tubing annulus to push a metal plunger up the well tubing, forcing a column of fluid to the surface. Gas and liquids are both collected. Liquids are separated from the gas, which is then routed to the pipeline for sale.

Figure 13: Green Completion Evaluation Flowchart

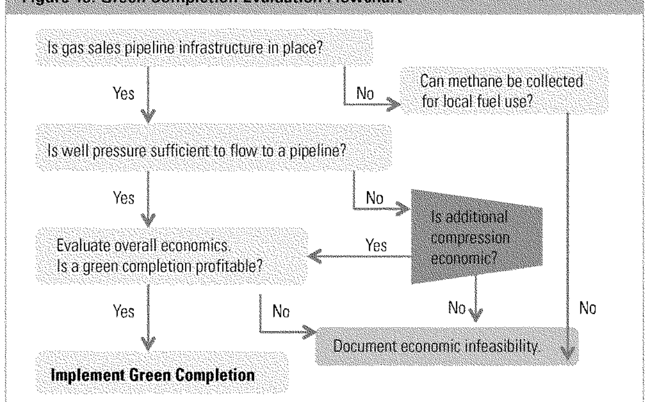
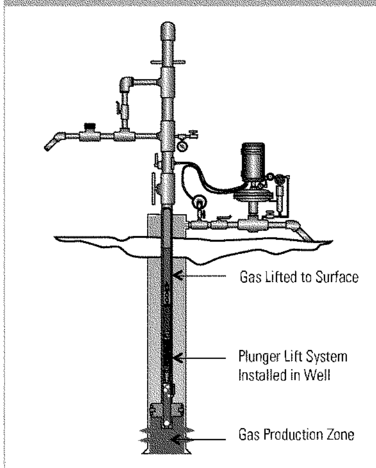


Figure 14: Plunger Lift System Schematic



Automated plunger lift systems have the added benefit of reducing the number of personnel that would be required to manually vent the well and extending the production life of the well.[67]

One vendor reports that plunger lift systems increase overall gas productivity and sales from each well by 10 to 20 percent.[68]

4.2.2 Opportunity

Reduction Target: 237 Bcf/year Less Green Completions Reduction

Natural gas production is now predominantly occurring in unconventional formations: low permeability sands, shale, and coal bed methane reservoirs.[69] In its comments on the EPA's proposed NSPS regulations for plunger lift systems, the American Petroleum Institute said: "According to the Energy Information Administration...some 338,056 (73 percent) wells out of a total gas well inventory of 461,388 produce 90 Mcf of gas (15 BOE or less) or less per day...These low rate wells are either impaired by liquids accumulation or are using a deliquification method to produce."[70]

Maximizing production from each well drilled can minimize the need to drill new wells and therefore reduce overall environmental impacts from natural gas production. However, low gas rate wells eventually cease production due to liquid accumulation in the wellbore and are often shut-in, unless a deliquification technique is employed on the well.

The EPA estimates that 4,700 to 18,250 Mcf/year of methane gas can be recovered per well with plunger lift systems.[70,71] In 2011, the EPA estimated that 237 Bcf of methane was emitted from well cleanups annually. A large fraction of these emissions could be controlled using plunger lift systems.

Plunger lift systems are low cost and use a well's own natural energy

4.2.3 Proposed EPA Regulations

The EPA's proposed NSPS regulations would not require the use of plunger lift systems to address well cleanups. Even if plunger lifts are more widely used than previously assumed, we strongly recommend that the EPA revise its proposal to require plunger lift systems to ensure that such systems are in use at all feasible sites.

NRDC acknowledges that there are many options for well deliquification. In any case, there is a methane control target (237 Bcf) that should be addressed by plunger lifts or other well deliquification methods that capture methane with similar efficiency and effectiveness. NRDC recommends that, while operators should have flexibility in selecting among the options, the basis for selection should be minimizing methane emissions.

4.2.4 Profit

Installing a plunger lift system in a gas well involves a small initial investment, estimated by the EPA to be between $2,600 and $10,400 per well.[72] Plunger lift system maintenance may cost about $1,300 per year, but yields other operational savings such as avoided chemical treatment of about $13,200 per year, resulting in a net savings.

Each plunger lift installed in an older gas well could result in 600 to 18,250 Mcf per year of recovered gas, valued at $2,000 to $103,000, when operations and maintenance savings are included. The value of methane gas recovered and sold rapidly covers that initial investment cost, as shown in greater detail in Appendix A, Table A2.

Most companies report a less than one-year payout and substantial profit thereafter, depending on the gas recovery rate. Future profits will be offset eventually by declines in gas recovery rates, and by minimal additional operating and maintenance costs, but since most plunger lift systems pay back in less than a year, plunger lift installations typically start profitable and remain profitable for many years after the initial investment.

The examples below, reported by industry, illustrate the profitability of plunger lift systems:

- Between 1995 and 1997, Mobil Oil installed plunger lifts in 19 wells at its Big Piney Field in Wyoming, reducing its emissions by 12,166 Mcf per year.[73]

- In 2000, BP installed plunger lift systems with automated controls on approximately 2,200 wells in the United States, and reported a 50 percent reduction in gas well blowdowns for liquid unloading by year 2004.[74] By 2006, BP reported the installation of "smarter" plunger lift automation systems, achieving a $15.5 million per year profit on an average annual recovery of 1,424 Mcf of methane gas per well.[75]
- In 2000, Conoco reported that installation of plunger lift systems in its low-pressure gas wells in Lea County, New Mexico reduced operating costs by more than 70 percent.[76]
- In 2006, Amoco reported that it installed plunger lifts at a cost of $13,000 per well at its Midland Texas field, resulting in electricity, well workover, and chemical treatment savings of $24,000 per year per well. In addition there was a small increase in gas production, which added about an additional $79,000 in profit to each well per year, for a total benefit of more than $100,000 per well.[77]
- In 2007, Devon Energy reported a 1.2 Bcf reduction of vented methane gas in its operations due to installation of plunger lift systems.[78]
- In 2010, the New Mexico Oil and Gas Association submitted testimony to the New Mexico Environmental Improvement Board confirming that plunger lift systems have been technically viable and economically attractive in the San Juan Basin.[79]

4.2.5 Additional Benefits

Automated plunger lift systems continuously optimize gas production. Regular fluid removal limits the periods of time that liquid loading "kills" the well and halts gas production.

The mechanical action of the plunger traveling up and down the tubing also prevents buildup of scale and paraffin in the tubing. Preventing excess scale and paraffin buildup reduces the cost of the chemical or mechanical swabbing treatments required to remove this buildup, and, in more serious cases, the cost of well workovers. The EPA reports additional savings associated with plunger lift systems ranging from $6,600 to $14,500 per well for reduced chemical treatment and workover costs.[80]

Gas venting near well operations creates potentially explosive vapor levels that can pose a human health hazard. Collection of potentially explosive gas vapors, rather than venting the gas to atmosphere, improves well site safety, reduces worker exposure to harmful vapors, and limits overall corporate liability.

Additionally, gas capture and sale reduces emissions, noises, odors, and citizen complaints associated with venting.

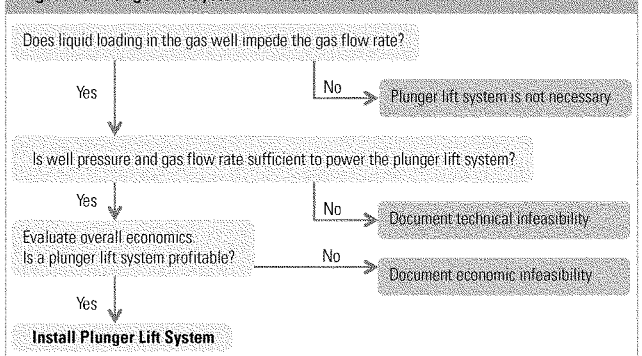
Unprocessed natural gas contains VOCs and HAPs, along with methane. Therefore, capture of this gas also reduces VOCs and HAPs pollution.

4.2.6 Limitations and Evaluation

Plunger lift systems are useful in gas wells that tend to fill with liquid, and have sufficient gas volume and pressure to power the plunger lift system. Such factors should be taken into account in determining applicability. In some cases, wells installed with plunger lifts may need to be vented for a short period of time to generate the differential pressure needed to resume well liquid removal. Even in this case, total methane emissions are substantially reduced. Also, a plunger cannot be run in a well bore with changing tube sizes, or wells with highly deviated directional or horizontal well bores.

Figure 15 provides a simplified evaluation flowchart showing the basic steps for evaluating whether a plunger lift system will be technically feasible and profitable.

Figure 15: Plunger Lift System Evaluation Flowchart



4.3 TRI-ETHYLENE GLYCOL DEHYDRATOR EMISSION CONTROLS

Glycol dehydrators are used to remove moisture from natural gas to improve gas quality, minimize corrosion in the gas sales line, and mitigate gas hydrate formation. A number of different glycols can be used in dehydration systems (e.g. triethylene glycol (TEG), diethylene glycol (DEG), ethylene glycol (MEG), and tetraethylene glycol (TREG)). TEG is the most commonly used glycol in industry.[81] TEG dehydrators vent methane gas to the atmosphere, but in many cases methane gas can be captured instead.

4.3.1 Technology Description

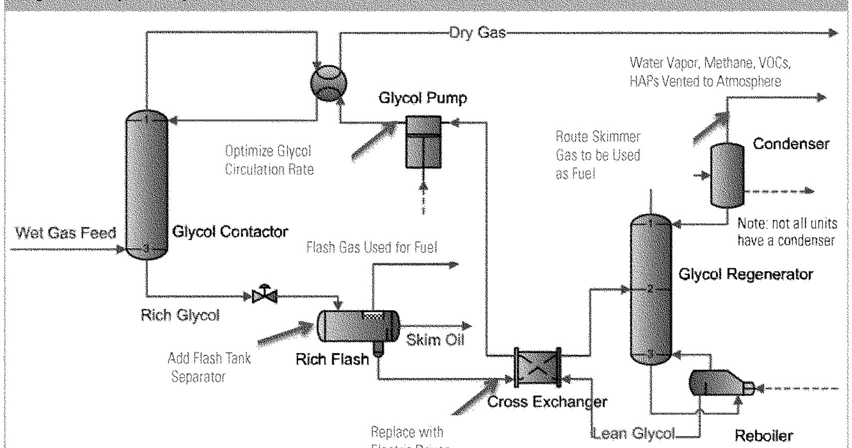
In some cases, if the design criteria can be met, a TEG dehydrator can be replaced with a desiccant dehydrator (see Section 4.4). However, desiccant dehydrators are limited to low gas flow rates—less than 5 MMcfd—and have temperature and pressure limitations. Therefore, for higher gas flow rates, the best solution is often to retrofit existing TEG dehydrators with emission controls.

A typical glycol dehydration system includes a glycol contactor, a glycol exchange pump, a driver to run the pump, and a glycol regenerator and reboiler. In some cases, a condenser is also installed downstream of the glycol regenerator. Figure 16 provides a schematic for a typical glycol dehydration unit. As shown in the diagram, natural gas with moisture content exceeding pipeline specifications ("wet gas") enters the glycol dehydration system and moisture is removed to achieve pipeline specifications ("dry sales gas").

A typical glycol dehydration system includes the following components:

- **Glycol contactor:** Wet gas enters the glycol contactor. Glycol removes moisture from the gas by the process of physical absorption. Along with removing moisture, the glycol also absorbs methane, VOCs, and HAPs. Dry gas exits the glycol contactor absorption colnmn and is either routed to a pipeline or a gas plant. The glycol contactor unit plays the primary role in dehydrating the gas to pipeline specifications, but the rest of the glycol dehydration system is required to convert the now moisture rich glycol back into a lean product that can be reused to dehydrate more incoming gas. Therefore, the next step in the process is to route the moisture rich glycol to regenerator and reboiler units to remove that moisture.
- **Glycol regenerator & reboiler:** Glycol loaded with moisture, methane, VOCs, and HAPs ("rich glycol") exits the bottom of the glycol contactor unit and is routed to the glycol regenerator and reboiler units to remove the absorbed components and return "lean" glycol back to the glycol contactor. If emission controls are not installed, methane, VOCs, HAPs, and water are boiled off and vented to atmosphere from the regenerator and reboiler units. One way to limit the amount of methane, VOCs, and HAPs emitted to the atmosphere from the regenerator and reboiler units is to install a flash tank separator.

Figure 16: Glycol Dehydration Unit Schematic



Source: Wikimedia Commons, Wikipedia: Glycol Dehydration

- **Flash tank separator:** Installation of a flash tank separator between the glycol contactor and the glycol regenerator/reboiler units creates a pressure drop in the system, allowing methane, and some VOCs and HAPs, to flash out of, or separate from, the glycol. The amount of pressure drop that can be created is a function of the fuel gas system pressure or compressor suction pressure because the methane gas flashed-off at the flash tank separator is then sent to be used as fuel in the TEG reboiler or compressor engine. Simply put, the pressure can only be dropped to a pressure that still exceeds the fuel gas pressure, allowing the collected methane gas to flow into the fuel system. Flash tank separators typically recover 90 percent of the methane and approximately 10 to 40 percent of the total VOCs that would otherwise be vented to atmosphere. Methane emissions can also be controlled by taking the simple step of adjusting the rate at which glycol circulates in the system.
- **Glycol recirculation pump:** Methane emissions are directly proportional to the glycol circulation rate. Circulating glycol at a rate that exceeds the operational need for removing water content from gas unnecessarily increases methane emissions. Glycol circulation rates are typically set at the maximum to account for peak throughput. Gas pressure and flow rate decline over time, requiring the glycol circulation rate to be adjusted to meet operational need. Optimizing the glycol circulation merely requires an engineering assessment and a field operating adjustment. If the glycol dehydration unit includes a condenser, methane emissions can be collected and used for fuel or destroyed rather than being vented to atmosphere.
- **Condensers:** Some glycol reboilers have still condensers to recover natural gas liquids and reduce VOCs and HAPs emissions. However, condensers do not capture methane (because it is a non-condensable gas); therefore, the addition of a condenser does not reduce methane emissions. In these cases, methane gas is typically vented to atmosphere. Alternatively, this methane gas (called "skimmer gas") can be routed to the reboiler firebox or other low-pressure fuel gas systems.[82]
- **Electric pumps or energy-exchange pumps:** Historically, gas-assisted glycol pumps have been used. Where there is an electric supply, the gas-assisted glycol pumps can be replaced with an electric pump. Gas-assisted pumps are driven by expansion of the high-pressure gas entrained in the rich glycol that leaves the contactor, supplemented by the addition of untreated high-pressure wet (methane rich) natural gas. The high-pressure gas drives pneumatic pumps. Much like pneumatically operated valves, pneumatically operated pumps vent methane. Electric pumps would reduce emissions, since they do not vent methane.

Regarding electric pumps or energy-exchange pumps, the EPA reports:

> *"The mechanical design of these pumps places wet, high-pressure TEG opposed to dry, low pressure TEG, separated only by rubber seals. Worn seals result in contamination of the lean (dry) TEG making it less efficient in dehydrating the gas, requiring higher glycol circulation rates. Replacing gas-assisted pumps with electric pumps increases system efficiency and significantly reduces methane emissions."*[83]

By comparison, electric pumps have lower emissions and no pathway for contamination of lean TEG by the rich TEG.

In summary, there are four straightforward solutions readily available to control methane emissions from TEG dehydrator units:

- Installing a flash tank separator
- Optimizing the glycol circulation rate
- Rerouting the skimmer gas
- Installing an electric pump to replace the natural gas driven energy exchange pump

4.3.2 Opportunity

Reduction Target 8 Bcf/year

The 2011 *Greenhouse Gas Inventory* estimates that gas dehydration systems emit approximately 8 Bcf of methane annually.[84]

In 2009, the EPA estimated that there were approximately 36,000 glycol dehydrators in operation in the U.S. natural gas sector.[85]

While a number of large glycol dehydrators are currently required by the EPA to install emission controls under the federal Maximum Achievable Control Technology standards (MACT standards at 40 CFR Part 63, Subpart HH), small glycol dehydrators are typically exempt from federal emission control requirements. Many small glycol dehydrator units do not have flash tank separators, condensers, electric pumps, or vapor recovery installed on the glycol regenerator.

Many small glycol dehydrators operating in the United States are exempt from federal emission control

Table [illegible]: Methane Capture Potential from TEG Dehydrator Controls

Technology	Methane Capture Mcf/year
Flash Tank Separator	[illegible]
Optimize Glycol Circulation Rate	[illegible]
Reroute Skimmer Gas	[illegible]
Install Electric Pump	[illegible]
Potential Methane Capture Range	[illegible]

A significant fraction of this 8 Bcf/year of emissions from this source can and should be captured (Table 5).

Installing Flash Tank Separator: In 2005, the EPA estimated that the installation of a flash tank separator, on average, resulted in 10 Mcf/day (3,650 Mcf/year) of methane gas captured for use as fuel for each TEG dehydrator (typically a 90 percent reduction in methane emissions).

In 2009, the EPA reported that flash tank separators were only installed on 15 percent of the dehydration units processing less than 1 MMcfd, 40 percent of units processing 1 to 5 MMcfd, and between 65 and 70 percent of units processing more than 5 MMcfd.[86] Chevron reported it has installed flash tank separators, recovering 98 percent of the methane from the glycol and reducing methane emissions from 1,450 Mcf/year to 47 Mcf/year.[87]

Optimizing Glycol Circulation Rate: In 2005, the EPA estimated that optimizing the glycol circulation rate could result in a wide range of methane capture from 1 to 100 Mcf/day (18,250 Mcf/year using a median estimate of 50 Mcf/day).[88]

Rerouting Glycol Skimmer Gas: In 2005, the EPA estimated that rerouting glycol skimmer gas could result in an average methane capture of 21 Mcf/day (7,665 Mcf/year).[89]

Installing Electric Pump: In 2007, the EPA estimated that between 360 and 36,000 Mcf/year in methane emission reductions could be achieved by installing an electric pump to replace the natural gas-driven glycol energy exchange pump. The wide range in methane emission reductions is a function of the large variation in equipment sizes. In Table 5 we use the number 5,000 Mcf/year per electric pump.[90]

In 2007, the EPA determined that the total potential emission reductions at any given glycol dehydration unit is a function of how many of these emission control solutions are installed, and estimated that the total reduction potential may range from 3,600 to 35,000 Mcf/year, or $14,600 to $138,000 of annual revenue. The 2011 *Greenhouse Gas Inventory* estimates the upper range of emissions at 38,000 Mcf/year.[91]

4.3.3 Proposed EPA Regulations

The EPA's proposed air toxics standards would cover new and existing small dehydrators located at major sources of HAPs.[92] The EPA classifies small dehydrators as units with an annual average gas flow rate less than 3 million Mcf/day at production sites, or 9.99 million Mcf/day at natural gas transmission and storage sites, or actual average benzene emissions less than 0.9 Mg/year.

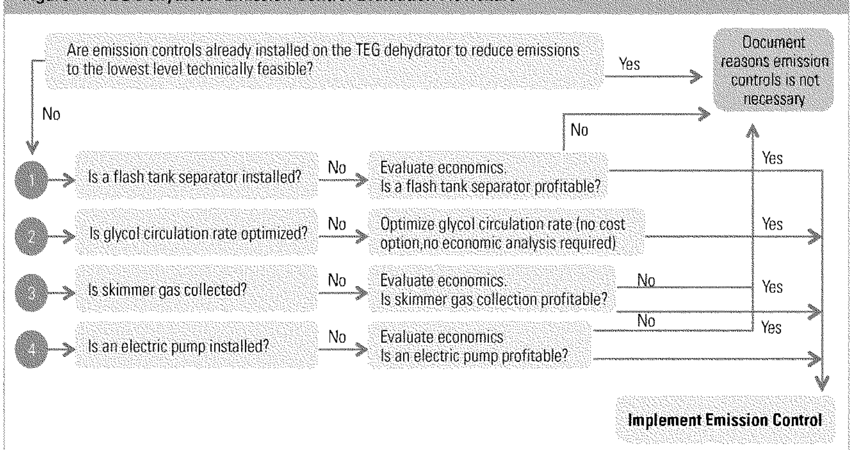
4.3.4 Profit

The EPA estimates that it costs on average:

- $5,000 to install a flash tank separator
- Less than $100 to adjust the glycol circulation rate
- $1,000 per unit to reroute glycol skimmer gas, with $100 per year of operating and maintenance costs[93]
- $1,400 to $13,000 to install an electric pump[94]

These technologies can be installed singly or in combination. Each unit, if equipped with the above technology, would capture approximately 3,600 to 35,000 Mcf per unit, per year. This translates to profits of between $14,000 and $138,000 per unit per year, as shown in greater detail in Appendix A Table A3. This technology has a payback period of less than a year, and can generate significant profits each year thereafter.

Figure 17: TEG Dehydrator Emission Control Evaluation Flowchart



4.3.5 Additional Benefits

One of the most important benefits of TEG dehydrator emission controls is the opportunity to reduce the amount of HAPs emitted to the atmosphere, especially benzene, a known human carcinogen. Along with methane gas, TEG dehydrators vent VOCs and HAPs to the atmosphere. In some cases, glycol dehydrators have still condensers and condensate separators to recover natural gas liquids and reduce VOCs and HAPs. But, if these units are not installed, VOC and HAP components (including benzene) are vented into the atmosphere.[95]

The installation of a flash tank separator reduces VOC and HAP emissions, improving air quality. The installation of a flash tank separator also improves the efficiency of downstream components (e.g. condensers) and reduces fuel costs by providing a fuel source to the TEG reboiler or compressor engine.[96]

4.3.6 Limitations and Evaluation

The option to reroute the skimmer gas can be employed only on dehydrators where a still condenser is installed. The following factors should be evaluated in assessing feasibility of installing an electric pump to replace the natural gas driven glycol energy exchange pump, as electricity may not be available at a remote well site: (1) the local electric grid's potential to make electric power available to a well site, (2) the potential to self-generate electricity on site using waste gas that might otherwise be vented or flared, or (3) availability of solar power.

Figure 17 provides a simplified evaluation flowchart showing the basic steps for evaluating whether TEG dehydrator emission controls are appropriate.

4.4 DESICCANT DEHYDRATORS

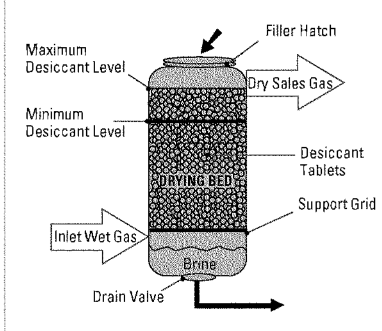
Desiccant dehydrators can be used as alternatives to glycol dehydrators to remove moisture from natural gas to improve gas quality, minimize corrosion in the gas sales line, and mitigate gas hydrate formation. Desiccant dehydrators do not emit significant quantities of methane gas into the atmosphere, and reduce emissions by up to 99 percent.

4.4.1 Technology Description

Desiccant dehydrators dry gas by passing the gas through a bed of sacrificial hygroscopic salt (the desiccant).[97] The salt type—typically calcium chloride ($CaCl_2$) or lithium chloride (LiCl)—is selected based on gas temperature and pressure and to match the gas operating conditions, as shown in Figure 18. Unlike a traditional glycol dehydrator, there are no pumps, contactors, regenerators, or reboilers, and only a small amount of methane is released intermittently when the unit is opened to replace the salt.

The amount of moisture that can be removed from a gas

Figure 18: Desiccant Dehydrator Schematic



stream is a function of the gas pressure and temperature. At high gas temperatures, desiccant dehydrators can form gas hydrates, which can plug the unit. Therefore, desiccant dehydrators are best suited for 5 MMcfd gas flow rates or less, with a low wellhead gas temperature (less than 70 degrees Fahrenheit). Glycol dehydrators are needed for gas flow rates exceeding 5 MMcfd, for higher gas pressures, or when operation is required over a wide range of pressures.[98]

4.4.2 Opportunity

Reduction Target: 8 Bcf/year

The 2011 *Greenhouse Gas Inventory* estimates that gas dehydration systems emit approximately 8 Bcf of methane annually.[99]

Desiccant dehydrators can be used to replace an existing TEG dehydrator. When this occurs, there is an initial capital investment required. For example, a 1 MMcfd unit costs about $12,500 to $16,000, but the operating and maintenance costs for a desiccant dehydrator are lower than those for a TEG unit (cost savings of about $1,800/year).[100,101] The EPA estimates that replacing a small TEG dehydrator with a desiccant dehydrator will capture about 1,000 Mcf/year of methane.[102] Larger units—up to 5 MMcfd—will cost incrementally more, but will have corresponding lower operating and maintenance costs and higher methane emission recovery.[103]

Of the 8 Bcf/year reduction target for dehydrators, most of the emissions are from small dehydrators that are exempt from MACT standards. Using desiccant dehydrators to replace aging glycol dehydrators, or as a lower emission alternative for new dehydration units, will reduce methane emissions from small dehydrators.

4.4.3 Proposed EPA Regulations

The EPA's proposed new air toxics standards include new and existing small dehydrators. Desiccant dehydrators are not specifically required.

While these proposed standards would cover both small and large glycol dehydrators, the EPA estimates that only 0.024 Bcf/year of methane would be captured (about 0.3 percent of the emissions from this source).

The EPA's proposed standards could be strengthened by requiring:

- Air toxics reductions of 98 percent (up from the proposed 95 percent)
- Better operational practices (e.g. optimized circulation rates)
- Portable desiccant dehydrators used during maintenance, and desiccant debydrators for gas flow rates of 5 MMcfd or less.

4.4.4 Profit

If a desiccant dehydrator is technically feasible in a new installation, it will be more profitable than a TEG dehydrator. In addition to having lower capital and operating and maintenance costs than a TEG dehydrator, it has the added benefit of being able to collect methane for sale.

The EPA estimates that profit could amount to $6,000 per year, including operations and maintenance savings. The initial investment of $16,000 for replacing a glycol dehydrator with a desiccant dehydrator is paid out in less than three years, as shown in greater detail in Appendix A, Table A4.[104]

In 2007, BP reported that it eliminated 858 glycol dehydrators, replacing them with desiccant dehydrators, for a $27 million profit and "immediate-payout." This amounts to a profit of $31,469 per unit total, or about $31,000 per year averaged over a 10-year period.[105]

4.4.5 Additional Benefits

Unprocessed natural gas contains VOCs and HAPs, along with methane. Therefore, capture of this gas also reduces VOC and HAP pollution.

4.4.6 Limitations and Evaluation

Desiccant dehydrators produce a liquid brine waste that must be either routed to a produced water tank for reinjection or disposed of as waste. There are also pressure, temperature, and gas flow limitations.

Figure 19 provides a simplified evaluation flowchart showing the basic steps for evaluating whether a desiccant dehydrator would be an option.

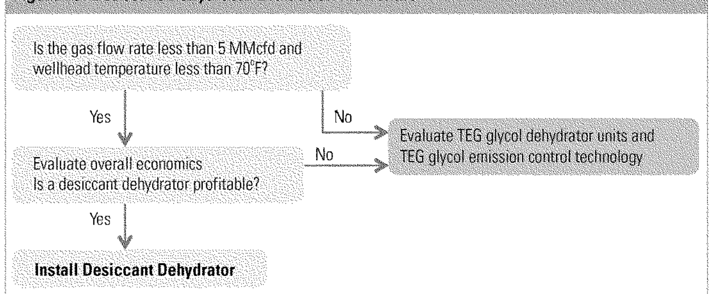
4.5 DRY SEAL SYSTEMS

Centrifugal compressors are used in the production and transportation of natural gas. Centrifugal compressors installed with wet seals have high-pressure seal oil that circulates between rings around the compressor shaft. This high-pressure oil is used as a barrier to prevent gas escape. The seal oil absorbs methane gas, however, and later the methane is vented to atmosphere, when the compressor seal oil gas is vented in a process called "seal oil degassing" (Figure 20).

Instead of using seal oil (wet seal), centrifugal compressors can use dry seals, in which high-pressure gas is used to seal the compressor. Changing out wet seals and installing dry seals reduces methane venting (Figure 21).

Wet seal technology is being phased out. In fact, more than 90 percent of new compressors are being sold with dry seal technology, due to the environmental and cost savings benefits it offers.

Figure 19: Desiccant Dehydrator Evaluation Flowchart



4.5.1 Technology Description

Dry seals prevent methane leaks by pumping gas between the seal rings, creating a high-pressure leak barrier when the compressor shaft is rotating (Figure 21). Typically, two dry seals are used in tandem to prevent gas leakage. When the compressor shaft is not rotating, the dry seal housing is pressed up tight against the rotating ring using a "dry seal spring," thereby preventing gas leaks.[106]

4.5.2 Opportunity

Reduction Target: 27 Bcf/year

The 2011 *Greenhouse Gas Inventory* estimates that approximately 1,500 centrifugal compressors with wet seals were operating in the U.S. O&G industry, with rod packing systems emitting approximately 27 Bcf of methane annually, a significant fraction of which can and should be captured.[107]

The EPA estimates that 80 percent of natural gas compression station methane emissions are emitted from compressors.[108] If wet seals are used in compressors for other applications in gas production, those compressors can also emit large amounts of methane. According to the EPA, wet seal oil degassing may vent between 40 and 200 standard cubic feet per minute (scfm), compared to about 0.5 to 3 scfm with a dry seal.[109] Dry seal technology offers a technically and economically feasible alternative to reduce these methane emissions.

4.5.3 Proposed EPA Regulations

The EPA's proposed NSPS regulations would require the use of dry seals for each new or modified centrifugal compressor located in the processing, transmission, and storage sectors. The standards would not apply to compressors at a well site or in the distribution sector.

The EPA estimates that the proposed NSPS would reduce methane emissions from compressors with wet seals by about 0.25 Bcf/year, about 1 percent of the compressor methane emissions from this source. This low control percentage is primarily because the NSPS would only affect new or modified or replaced leakage sources, while the bulk of the emissions are from existing sources.

The proposed regulations could be further enhanced by requiring equipment and operational requirements for existing compressors. New compressors represent just 2 percent of all centrifugal compressors in the processing, transmission and storage sectors. Compressors are added or replaced in these sectors at an extremely low rate. Therefore, a standard applying only to such compressors would leave most of the emissions untouched.

Figure 20: Centrifugal Compressor Leaks Schematic

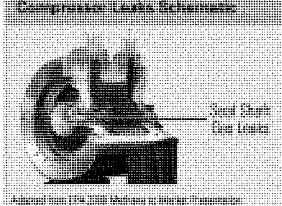
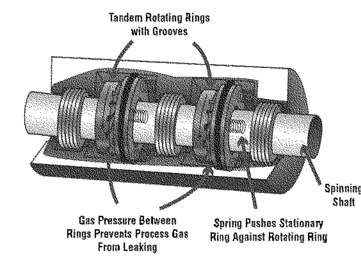


Figure 21: Centrifugal Compressor Dry Seals



Adapted from EPA Lessons Learned, Replacing Wet Seals with Dry Seals in Centrifugal Compressors.

4.5.4 Profit

The actual costs for a dry seal system will depend on compressor operating pressure, shaft size, rotation speed, and other site-specific factors. The EPA reports that a dry seal retrofit costs on average $324,000, but results in an operations and maintenance cost savings of more than $100,000 per year and can generate up to $400,000 in additional annual revenue from captured methane, resulting in a payout of approximately one year.[110,111] One of the major factors in the profit equation is the lower O&M costs for dry seals—$8,400 to $14,000 per year—compared to wet seal costs of $140,000 per year per compressor or more.

The EPA's 2011 *Greenhouse Gas Inventory* and other sources estimate the leak rate to be approximately 18,000 to 100,000 Mcf per year. If captured and sold, this could annually yield up to $400,000 in additional revenue, and up to $120,000 in operations and maintenance savings. Additional details are provided in Appendix A, Table A5.

Using the EPA's estimate that wet seal oil degassing may vent between 58 and 288 Mcf/day, compared to 0.7 to 4 Mcf/day with a dry seal, and using current gas prices, an operator may save up to $400,000 per year, per compressor.[122] However, the actual profits will vary based on site-specific circumstances.

In 2008, Petróleos Mexicanos (PEMEX) assessed the benefits of converting from wet seals to dry seals on centrifugal compressors at a compression station in southern Mexico.[113] PEMEX found a gas savings of 33.5 scfm per seal, and a gas savings of 35,000 Mcf/year (resulting in greenhouse gas emissions reduction of 7,310 metric tons of carbon dioxide equivalent per year), and a profit of $126,690 annually.[114]

Targa Resources and the Gas Processors Association report that replacing a wet seal with a dry seal on a 6 inch shaft beam compressor that operates approximately 8,000 hours per year, leaking at 40 to 200 scfm, will pay out in four to 15 months, yielding more than $1 million in net present value, assuming a 10 percent discount rate in a span of five years, and more than a 170 percent rate of return.[115]

4.5.5 Additional Benefits

Upgrading compressor seals can reduce power requirements and downtime, improve compressor reliability, and lower operating costs by eliminating seal oil costs and associated maintenance.[116]

4.5.6 Limitations and Evaluation

A compressor-specific, site-specific evaluation is necessary to determine if conversion to dry seals is technically feasible. A conversion to dry seals may not be possible on some compressors because of compressor housing design or other operational or safety factors.

Figure 22 provides a simplified evaluation flowchart showing the basic steps for evaluating a dry compressor seal conversion.

4.6 IMPROVED COMPRESSOR MAINTENANCE

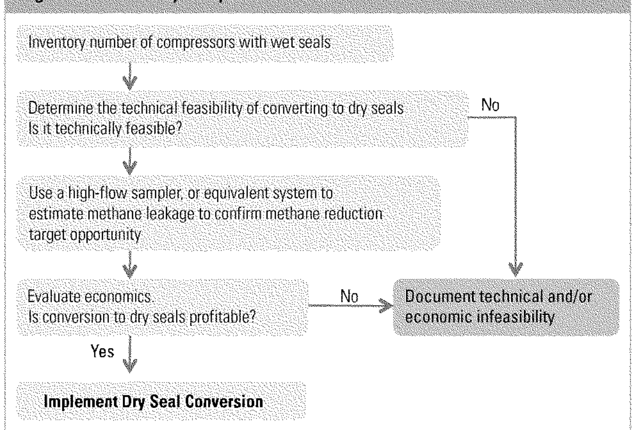
Reciprocating compressors leak methane from a component called a rod packing case. A common practice is to route the rod packing emissions outside the compressor building and vent the methane emissions directly into the atmosphere. Methane emissions can be reduced by replacing worn out rod packing.

4.6.1 Technology Description

Rod packing systems are used to maintain a seal around the piston rod, preventing gas compressed to a high pressure in the compressor cylinder from leaking, while still allowing the piston rod sbaft to move freely. A series of flexible rings are fitted around the piston rod shaft, held in position by packing material and springs.

Methane leaks occur between the rings and piston rod shaft, around the outside of the rings, and between the packing (Figure 23). Packing leaks can occur for a number of reasons, such as a worn piston rod, an incorrect amount of lubrication, dirt or foreign matter in the packing, or packing material out of tolerance.[117] The amount of leakage will be a

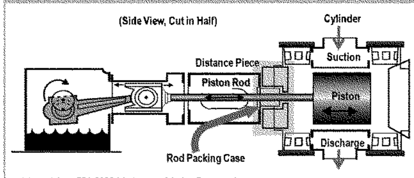
Figure 22: Wet to Dry Compressor Seal Evaluation Flowchart



function of the amount of misalignment between the piston rod, packing materials, and rings and packing case. Also, misalignment of the piston rod and any imperfections on the piston rod surface can cause leakage.[118]

Rod packing case leaks are also a function of the quality of initial installation, packing material selection, and the way in which the unit was operated during the initial, or break-in, operating period.

Figure 23: Reciprocating Compressor Rod Packing Leaks Schematic



Adapted from EPA 2009 Methane to Market Presentation.

4.6.2 Opportunity

Reduction Target: 75 Bcf/year

In 2006, the EPA estimated that more than 51,000 reciprocating compressors were operating in the U.S. natural gas industry with, on average, four cylinders each, for a total of more than 200,000 piston rod packing systems in service.[119] The 2011 *Greenhouse Gas Inventory* estimates that these systems emit 75 Bcf of methane annually, a significant fraction of which can and should be captured.[120]

As with centrifugal compressors, an impediment to rod packing replacement is the equipment downtime required to make the replacement. However, routine repair and maintenance is a good business practice.

4.6.3 Proposed EPA Regulations

The EPA's proposed NSPS regulations for reciprocating compressors require replacement of rod packing every 26,000 hours of operation (approximately every three years). These standards would only apply to reciprocating compressors at processing stations, gathering and boosting stations, transmission stations and underground storage facilities. The standards would not apply to compressors at a well site or beyond the city gate (distribution sector).

The EPA estimates that the proposed NSPS regulations would reduce emissions from reciprocating compressors by about 0.3 Bcf/year, less than 1 percent of the methane emissions from these sources. This is primarily because the NSPS would only apply to new or replaced reciprocating compressors starting from the time of installation, whereas the bulk of the emissions come from existing compressors. It does not appear that the proposed standards would apply when an existing compressor is taken offline for maintenance.

The proposed regulations could be further strengthened by requiring equipment and operational requirements for existing compressors. New compressors represent just 3 percent of all reciprocating compressors in the processing, transmission and storage sectors. Compressors are added or replaced in these sectors at a low rate; therefore, a standard applying only to new compressors will leave most of the emissions untouched. The EPA should also require emission abatement at the wellhead (production sector). While replacement based on hours of operation is a good minimum threshold, the EPA should also consider requiring regular leak-rate tests and early replacement if leakage is deemed too high.

4.6.4 Profit

Operators that carefully monitor and replace compressor rod packing systems on a routine basis can reduce methane emissions and reduce piston rod wear, both of which increase profit.[121]

The 2011 *Greenhouse Gas Inventory* uses a leak rate of 875 scf/hour (21,000 scf/day), equating to approximately $100 of gas leaking from each compressor each day it is not repaired.

The EPA estimates that refurbishing the rings and packing material may cost between $135 and $2,500, depending on the size of the unit. Rod replacement can range from $2,400 to $13,500, depending on the number of rods replaced.[122]

The pace at which replacements are necessary is a function of the compressor type, use, maintenance and operating conditions, and is highly variable. In most cases, though, payout is achieved in less than a year. The EPA has estimated that on average, the annual investment expense of replacing one rod packing system is about $600, with an initial investment of about $1,600. The methane gas captured has a value of about $3,500 per year, allowing payout to be achieved in less than half a year.[123] Another EPA reference reports a slightly lower initial cost for replacing rod packing of $1,200, but with similar natural gas savings, to allow for payout in less than half a year.[124] Additional detail is shown in Appendix A, Table A6.

4.6.5 Additional Benefits

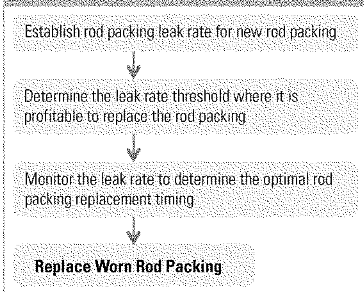
Collection of methane and other gas vapors at O&G operations creates a safer working environment by reducing potentially combustible vapors at the work site.

4.6.6 Limitations and Evaluation

One major consideration in deciding whether to replace worn rod packing is the cost and feasibility of taking the compressor out of service to make the repair. Larger facilities with spare compressor capacity will not be as significantly affected as smaller operations, where repairs may require a complete shutdown. Other variables affecting cost savings include the amount of wear already on the rings and rod shaft, fit and alignment of packing parts, and cylinder pressure.

Figure 24 provides a simplified evaluation flowchart showing the basic steps for evaluating rod packing replacement.

Figure 24: Rod Packing Replacement Evaluation Flowchart

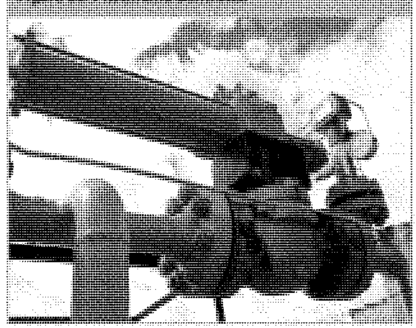


4.7 LOW-BLEED OR NO-BLEED PNEUMATIC CONTROLLERS

Pneumatic controllers are used to regulate pressure, gas flow, and liquid levels, and to automatically operate valves. They are used extensively in the O&G industry.

Pneumatic controllers are designed to release methane gas to the atmosphere as part of normal operations. Some pneumatic controllers bleed at a low rate (low-bleed) and others bleed at a high rate (high-bleed). A high-bleed controller is defined by the EPA Natural Gas STAR Program as a device that releases 6 scf/hour or more. Converting high-bleed controllers to low-bleed controllers, or moving away from gas-operated controllers altogether in favor of instrument air controls, reduces methane emissions.

Figure 25: Pneumatic Controller



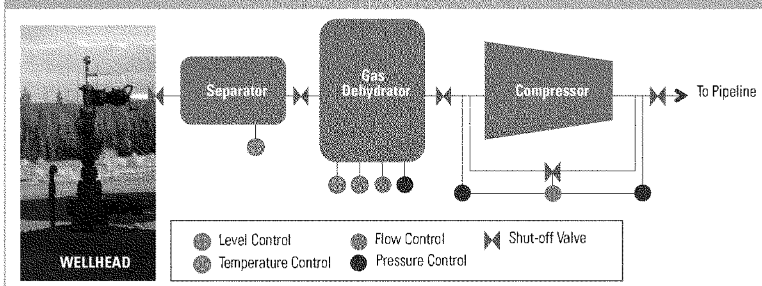
iStockphoto

Colorado requires O&G operators to install low-bleed or no-bleed pneumatic controllers at all new facilities and whenever a device is repaired or replaced, if technically feasible.[125] Wyoming's Oil and Gas Production Facility Guidance includes upgrading to low-bleed or no-bleed pneumatic controllers, or routing methane to a collection system during a repair or replacement.[126]

4.7.1 Technology Description

Pneumatic controllers use clean, dry pressurized natural gas to provide a power supply to measure process conditions (e.g. liquid level, gas pressure, flow rate, temperature) and control

Figure 26: Pneumatic Controller Locations in Natural Gas Production



Adapted from EPA 2008 Methane to Market Presentation

Harvey Consulting, LLC ©

the conditions to a set point. Figure 25 shows a pneumatic controller. Figure 26 shows the locations in O&G operations where pneumatic controllers may be used.

There are three main pneumatic controller designs:

1. Intermittent bleed controllers that release gas only when the valve is stroked open or closed
2. Continuous bleed controllers that modulate flow, liquid levels, or pressures
3. Self-contained controllers that release gas back into piping and not to the atmosphere[127]

There are four main options for reducing methane emissions from pneumatic controllers:

1. Replacing high bleed pneumatic controllers with low- or no-bleed controllers
2. Retrofitting pneumatic controllers with bleed reduction kits
3. Converting natural gas pneumatics to instrument air
4. Performing routine maintenance to repair leaking gaskets, tube fittings, and seals

4.7.2 Opportunity

Reduction Target: 99 Bcf/year

The 2011 *Greenhouse Gas Inventory* estimates that pneumatic controllers vented 99 Bcf of methane into the atmosphere.[128] Emissions are primarily generated from the production, processing, and transmission and storage sectors. The EPA also estimates that 84 percent of pneumatic controller emissions come from O&G production.[129] According to the American Petroleum Institute, there are approximately 1 million existing wells, and three controllers per well, indicating that there are a minimum of three million controllers in operation at well sites alone. The EPA reports that the typical high-bleed controller releases 140 Mcf/year of gas to the atmosphere.[130] Fortunately, nearly 80 percent of all high-bleed pneumatic controller can be replaced with low-bleed equipment or retrofitted to reduce methane emissions.[131]

Taking into account the EPA's assessment that 80 percent of high-bleed devices can be replaced or retrofitted, we consider that a very large fraction of the 99 Bcf/year emissions can be captured.

4.7.3 Proposed EPA Regulations

The EPA's proposed NSPS regulations require instrument air controllers that have zero methane emissions to be installed at processing plants. The EPA also proposes that low-bleed pneumatic controllers, with a limit of 6 scfh, be used in the production, transmission, and storage sectors. Requirements would apply to newly installed pneumatic controllers, including replacement of existing devices. The proposal would exclude pneumatic controllers that are located in the distribution segment, as well as existing controllers.

The EPA estimates that the proposed NSPS regulations would reduce emissions from high-bleed pneumatic controllers by about 4.5 Bcf/year, or about 5 percent. The emission reduction is small because the proposed NSPS would only apply to pneumatic controllers at the time of installation, whereas the bulk of the emissions are from the existing fleet of controllers.

NRDC recommends that the EPA should require that existing sources be controlled to maximize methane emission reductions. The EPA should also consider regulating emission reductions from the distribution sector, and requiring no-bleed controllers at locations outside the processing sector where feasible.

4.7.4 Profit

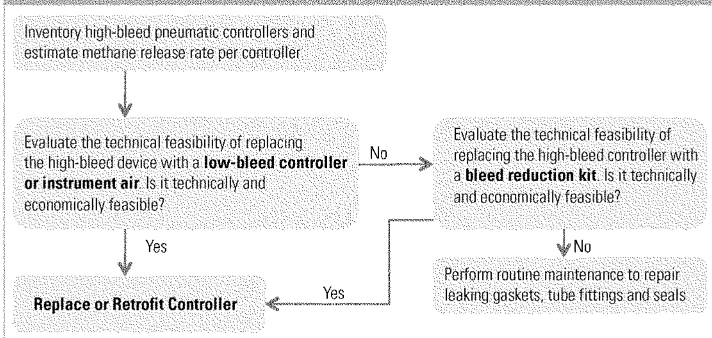
In 2005, the EPA reported that the incremental cost of replacing high-bleed controllers with low-bleed controllers was approximately $350 per device, resulting in a $1,100 annual operating and maintenance cost savings and a payback of less than one year for each device.[132] Natural gas savings of $700 or more is also possible. The EPA estimates that retrofitting a pneumatic controller with a bleed reduction kit costs, on average, $500, and pays out in nine months.[133] An EPA *Lessons Learned* report from 2006 also reports similar cost and natural gas savings, but with smaller operational and maintenance savings.[134]

While conversion from natural gas pneumatic controllers to instrument air is estimated to be more costly, at $10,000 per conversion and $7,500 in annual operating and maintenance costs, there are substantial annual natural gas savings of more than $20,000 per year and payback in less than two years.[135,136] In 2006, the EPA estimated the cost/benefit of replacing large gas-operated controllers with instrument air controllers.[137] The EPA estimated the cost to be approximately $60,000 per controller. The natural gas savings were commensurately larger at approximately $80,000 per year, rendering the investment profitable with a payback period of just under one year. Additional detail is shown in Appendix A, Table A7 and A8.

BP reported that it replaced 11,500 high-bleed pneumatic controllers with low- or no-bleed controllers in six states, during the period of 1999 to 2002, capturing 3.4 Bcf/year .[138] The program yielded a net present value of $65 million for a capital investment of $4 million. BP also reported that it had installed 411 pneumatic pump pressure regulators, reducing gas use by 0.4 Bcf/year, at a cost of less than $50,000, for a net present value of $8.4 million.

QEP Resources Inc., Shell Upstream Americas, Ultra Petroleum, Devon Energy, EnCana, and other gas producers in Wyoming have replaced pneumatic controllers with new low-bleed controllers. Instead of gas venting the gas is routed to a pipeline for sale.[139]

Figure 27: Pneumatic Controller Evaluation Flowchart



4.7.5 Additional Benefits

Upgrading pneumatic controllers to use instrument air increases operational efficiency, system-wide performance, and reliability. It also improves monitoring of gas flow, pressure, and liquid levels. Excess instrument air can be used for other equipment (e.g. pumps and compressor starters).

4.7.6 Limitations and Evaluation

The EPA estimates that 80 percent of all high-bleed controllers can be retrofitted or replaced with low-bleed equipment, leaving 20 percent of the controller inventory not feasible for this technology.[140]

Figure 27 provides a simplified evaluation flowchart to show the basic steps for evaluating replacement of a high-bleed to a low or no-bleed pneumatic controller.

4.8 PIPELINE MAINTENANCE AND REPAIR

Methane is typically vented into the atmosphere when a gas pipeline is repaired or replaced, or must be cut to install a new connection point. Typically an operator will isolate the pipeline section to be worked on by shutting pipeline valves on either side of the repair, replacement, or connection point. The gas contained in the piping section is typically vented into the atmosphere to eliminate a potential fire or explosion risk while work is completed on the piping.

Subject to a thorough safety evaluation, alternatives exist to mitigate methane release. These alternatives involve either re-routing gas to be burned as fuel or allowing work to be conducted on the pipeline while it is in operation.

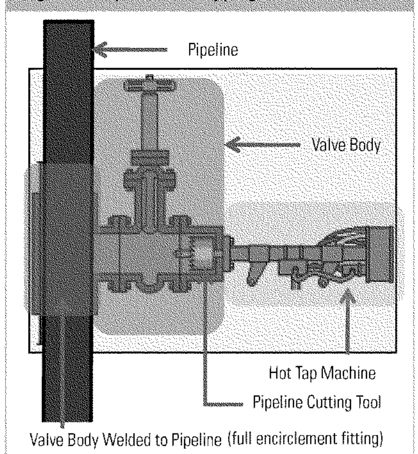
During pipeline repair, methane gas venting can be mitigated by:

- Using hot tap connections
- Re-injecting gas into a nearby low-pressure fuel system,
- Using a pipeline pump-down technique to route gas to sales

4.8.1 Technology Description

Hot Tap: Hot tapping a pipeline allows an operator to make a connection to a pressurized piping system without causing any service interruption. Hot tapping is completed by first welding a branch fitting and permanent valve body onto the pipeline while the pipeline remains in service. Next, the hot tapping machine is installed on the valve body (Figure 28). The hot tap pipeline cutting tool is inserted through the valve body and used to cut into the pipeline while maintaining

Figure 28: Pipeline Hot Tapping Schematic



a complete seal between the valve body and the hot tap machine. This process does not allow any methane gas to escape. Once the pipeline wall is cut, the piece of pipe is removed along with the cutting tool by pulling both back through the valve body. The valve is closed and the hot tap machine is removed. Finally the branch line is connected and installed without releasing any methane into the environment.

Hot tapping is not a new technology; it has been in use for a number of years.[141] However, hot tapping techniques and equipment have improved in quality, availability, and safety. More technicians and engineers are trained on safe use and operation, and necessary equipment is now available in the sizes typically used.

Re-injecting gas into a low pressure fuel system: In some cases, complete gas evacuation is required to safely repair, replace, or conduct maintenance on a pipeline section. Rather than venting methane to the atmosphere, an operator can de-pressure the pipeline to a nearby low pressure fuel system. Some pipelines are initially designed and installed with a bypass connection from the high pressure pipeline to a lower pressure fuel gas system. If a permanent bypass connection does not exist, a temporary bypass connection can be installed.

Pipeline pump-down technique: Gas can be removed from the pipeline by using in-line compressors along, or in sequence with, portable compressors. As explained above, an operator often will isolate the pipeline section to be worked on by shutting in pipeline valves on either side of the repair, replacement, or connection point. The gas contained in the piping section is then vented into the atmosphere to eliminate a potential fire or explosion risk. Alternatively, in the pipeline pump-down technique, the operator only shuts in one valve (the upstream valve), which stops any new gas from entering the pipeline section to be worked on. Then gas is removed from the pipeline section by running an in-line compressor located downstream of the repair section. This technique will not completely remove all the gas in the pipeline section, but may reduce the gas pressure or concentration to a level that is safe for some repairs (Figure 29A).

Use of a portable compressor, alone or in addition to an existing in-line compressor, can remove up to 90 percent of the gas in the pipeline segment because portable compressors have a 5 to 1 compression ratio, compared to in-line compressors that are rated at 2 to 1.[142] To use a portable compressor, there must be a valve manifold at the downstream pipeline location to temporarily install the compressor during the repair work (Figure 29B).

Figure 29A: Pipeline Pump-Down Technique Using In-Line Compressor Schematic

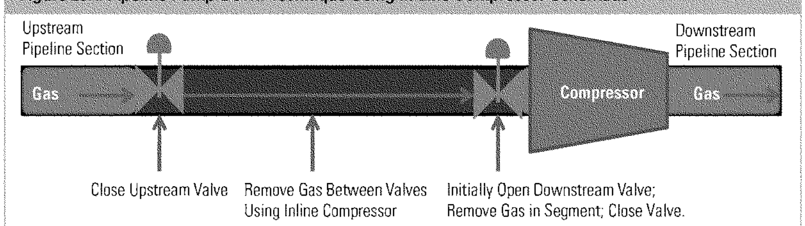
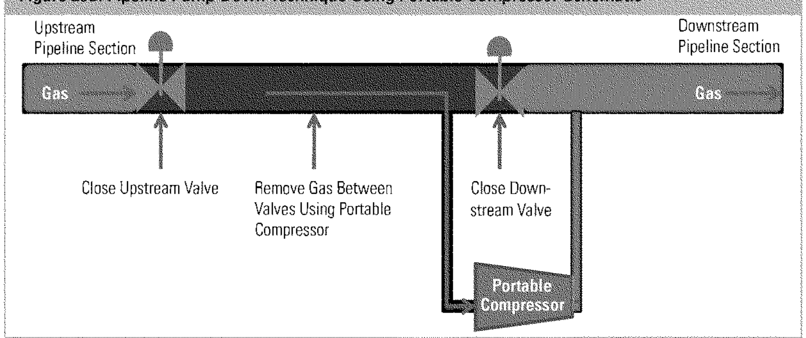


Figure 29B: Pipeline Pump-Down Technique Using Portable Compressor Schematic



4.8.2 Opportunity

Reduction Target: 19 Bcf/year

The 2011 *Greenhouse Gas Inventory* estimates that routine maintenance and pipeline upsets resulted in 19 Bcf/year of methane vented into the atmosphere.[143]

For a pipeline ranging from 4 to 18 inches in diameter and operating between 100 and 1,000 psig, the EPA estimates that up to 2,000 Mcf of methane gas is vented when a pipeline is blown down to make a new connection, and 6,000 Mcf is vented when replacing pipe.[144] The amount of gas contained in the pipeline section will be a function of pipeline size, pipeline length between isolation valves, and gas pressure. Thus, gas venting rates and volumes will vary substantially.

4.8.3 Proposed EPA Regulations

The EPA's proposed NSPS and existing air toxics standards do not include pipeline maintenance and repair as a means to control methane. NRDC recommends that the EPA require methane control during maintenance and repair where safe and feasible.

4.8.4 Profit

Use of a hot tap tool prevents venting gas into the atmosphere, allowing that gas to reach market, and eliminates the cost of evaluating the pipeline to install the connection. Hot tap profitability will vary widely based on the pipeline size, flow rate and number of taps done in a period of time. However, in general the EPA reports that payback is short (less than one year) and the procedure is profitable.[145]

The EPA estimated that the capital cost of installing a low pressure piping bypass to re-inject gas during a pipeline blowdown into a low-pressure fuel system is less than $1,000.[146]

The pipeline pump-down technique is most profitable for higher pressure, higher volume pipelines with existing in-line compressors, or where valve manifolding exists to easily connect a portable compressor.

Overall, use of in-line compressors to remove gas from a pipeline during a pipeline pump-down technique is very profitable because there is no initial investment or rental costs, and payback is essentially immediate. If portable compressors are required, economics will vary and will require a site-specific evaluation. Still, this procedure is typically profitable, with a short payout.[147] Gas collected by the compressors can be routed to a gas sales line.

4.8.5 Additional Benefits

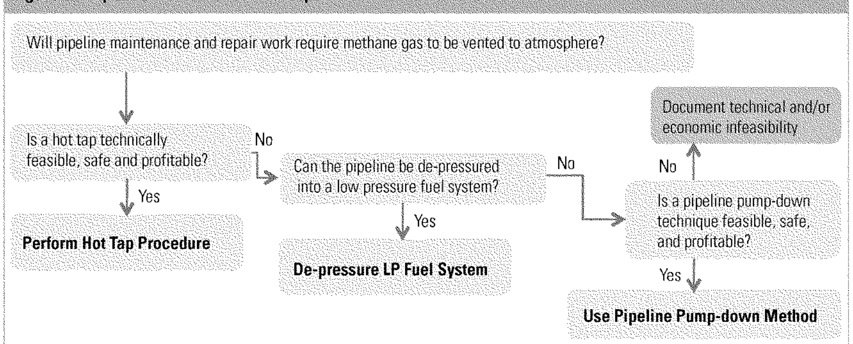
Continued operation of a pipeline during repair, maintenance, and installation of new connections eliminates disruption to gas service.

4.8.6 Limitations and Evaluation

The use of hot tap equipment and techniques requires a safety review and qualified personnel to safely operate the equipment, and there are some cases where use of hot tapping equipment is not safe or recommended. In these cases, advice can be sought from corporate health, safety, and environment experts to recommend alternate ways to avoid methane venting. Some repair, replacement, and pipeline connection plans require complete gas removal from the pipeline and a full purge to ensure the safety of personnel.

Figure 30 shows the basic steps for evaluating options to mitigate methane release from a pipeline during maintenance and repair work.

Figure 30: Pipeline Maintenance and Repair Evaluation Flowchart



4.9 VAPOR RECOVERY UNITS (VRUs)

Crude oil and condensate tanks that vent to atmosphere emit methane through three different mechanisms: flashing losses, working losses, and standing losses. To avoid methane emissions, a vapor recovery unit can be installed on the tank to capture methane gas for sale or to be used as fuel.

4.9.1 Technology Description

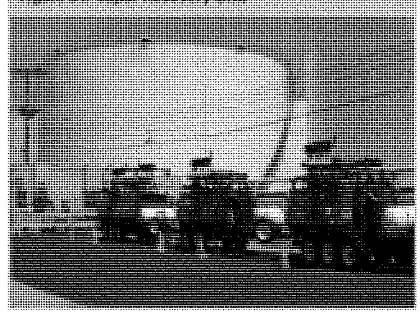
When liquid petroleum and natural gas are produced from a well, they are processed through a separator to partition oil, gas, and water. Oil, condensate, and gas are sold to market. Water is either re-injected or handled as waste.

Liquid petroleum is sometimes stored in tanks prior to delivery to a pipeline or other transportation method. Gas liquids (condensate), in some cases, are produced and collected in a tank. When oil leaves the last phase of separation, some amount of methane gas is still trapped in the oil; the amount of methane is dependent on the last-stage separator pressure.

Since the separator pressure is higher than the pressure in a crude oil or condensate tank, methane gas will escape from the crude oil or condensate during transfer into the tank. Liberation of natural gas is commonly referred to as "flashing" of natural gas from the oil. Flashed gas, typically, has a high BTU value and sales value.

Fewer flashing losses will be generated from an oil storage tank if a facility reduces the operating pressure of the low-pressure separator or heater equipment just upstream of the oil storage tank. In these cases, less gas will be routed to the tanks. These optimizations can be accomplished by adjusting operating pressures with minimal capital and operational costs.

Figure 31: Vapor Recovery Unit



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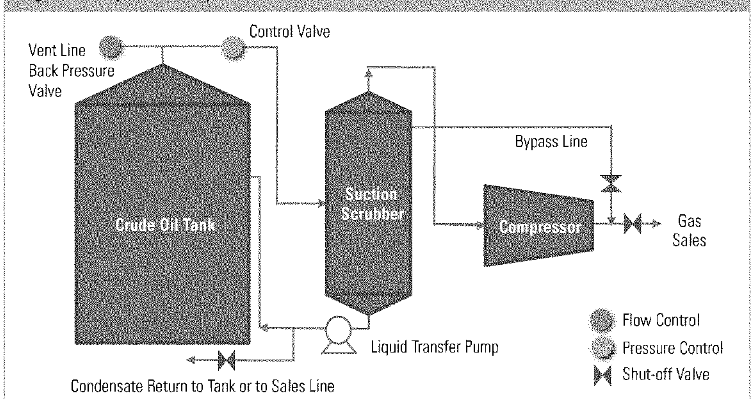
Once crude oil and condensate are in the tank, they will continue to release methane gas when tank contents are agitated (working losses), which typically occurs during filling and removal of oil or condensate from the tank, and through standing losses during seasonal and daily temperature and pressure changes.

Vapor recovery units can typically capture up to 95 percent of the methane that would ordinarily be vented to atmosphere. Figure 31 shows vapor recovery equipment. Captured methane gas can be sold or used as fuel. Figure 32 is a schematic showing the typical equipment configuration needed for a vapor recovery system.

For sites where electric power is available, the EPA recommends conventional rotary or screw type compressor vapor recovery units. For sites without electric power, an

Figure 32: Vapor Recovery Unit Schematic



© M.A. Goodyear, A.L. Graham et al, Vapor Recovery of Natural Gas Using Non-mechanical Technology ejector vapor recovery unit can be used if there is a high-pressure compressor with spare capacity.[148]

TotalFinaElf E&P USA, Inc. reports that it recovered $334,000 in gas per year from its El Ebanito O&G facility tanks in Starr County, Texas using the Venturi Jet Ejector System (patented by COMM Engineering).[149] Patented by Hy-Bon Engineering, the Vapor Jet System is another option if there is produced water available at the site to operate the system. A small centrifugal pump forces water into a Venturi jet, creating a vacuum effect to move low-pressure gas to a gas sales line or fuel use intake point.

If gas is collected in the vapor recovery units, it must be at sufficient pressure to enter the intended gas pipeline or fuel system. If this is not the case, additional compression is required at an additional cost.

4.9.2 Opportunity

Reduction Target: 21 Bcf/year

The 2011 *Greenhouse Gas Inventory* estimates that storage tanks vent approximately 21 Bcf/year of methane to the atmosphere.[150] Some crude oil tanks are required—by EPA and state regulation—to install vapor recovery units, however many smaller tanks do not have vapor recovery units installed.

4.9.3 Proposed EPA Regulations

The EPA's proposed NSPS for storage vessels would require at least 95 percent of VOC reductions for new and modified storage vessels.[151] These requirements would apply to vessels with a throughput equal to or greater than one barrel of condensate per day or 20 barrels of crude oil per day, which are equivalent to VOC emissions of about 6 tons per year.[151] Controls would include either the installation of a VRU or the use of a combustion device. At the same time, the EPA is proposing revised air toxics standards for storage vessels. The standards would apply to new and modified sources as well as existing sources. The EPA is proposing a 95 percent HAP reduction requirement, which would also reduce VOC emissions at these sources by 95 percent. In order to avoid duplication in compliance requirements (monitoring, recordkeeping, and reporting), the EPA is proposing that sources which are subject to the NESHAPs requirements would not be subject to NSPS requirements.

The EPA estimates that the proposed NSPS and NESHAPs regulations would reduce methane emissions from storage tanks by about 0.52 Bcf/year, or just under 3 percent of the emissions from this source, because the proposed rules would not apply to most of the uncontrolled tanks currently in operation.

NRDC recommends that the EPA's proposed regulations be strengthened by reducing the threshold for emission control on smaller tanks (e.g., by aggregating small tanks into a battery of tanks and considering emissions of the entire battery). The EPA should also require emissions reductions from produced water tanks, and require 98 percent control efficiency for VRUs (up from 95 percent).

4.9.4 Profit

The amount of profit from vapor recovery units will vary widely, based on site-specific parameters. The EPA's Methane to Markets program found that tank vapor recovery projects can be profitable (Table 6). Depending on size of the systems,

Table 6: Crude Oil Tank Vapor Recovery Unit (VRU) Economics

Financial Analysis for a Conventional VRU Project

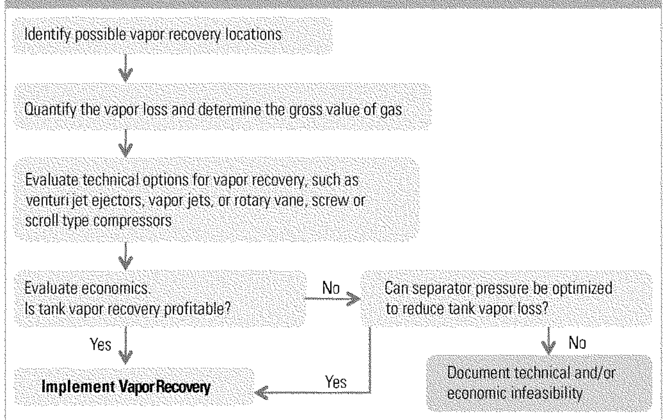
Peak Capacity (Mcf/day)	Installation & Capital* Costs	O&M Costs (year)	Value of Gas** (year)	Annual Savings	Simple Payback (months)	Internal Rate of Return %
25	$35,738	$7,367	$18,262	$10,895	39	28%
50	$46,073	$8,419	$36,524	$28,105	20	60%
100	$55,524	$10,103	$73,048	$62,945	11	113%
200	$74,425	$11,787	$146,097	$134,310	7	180%
300	$103,959	$16,839	$365,242	$348,403	4	335%

Adapted from: EPA Natural Gas STAR, Reducing Methane Emissions with Vapor Recovery on Storage Tanks, Lessons learned from the Natural Gas STAR Program, Newfield Exploration Company, Anadarko Petroleum Corporation, Utah Petroleum Association, Interstate O&G Compact Commission, Independent Petroleum Association of Mountain States, March 23, 2010.

*Unit cost plus estimated installation of 75 percent of unit cost

** $4.00 per Mcf x 1/2 peak capacity x 365 (original price as per report was $6.22)

Figure 33: Vapor Recovery Unit Evaluation Flowchart



capital and installation costs range from $36,000 to $104,000, methane capture at between 5,000 and 91,000 Mcf/year, and profits are between $4,000 and $348,000. Additional detail is provided in Appendix A, Table A9. Payback periods range from a few months to about three years, depending on flow rate and scale of the unit.[152,153]

Additional examples of tank vapor recovery profitability include:

- Anadarko reported netting $7 million to $8 million between 1993 and 1999 by installing more than 300 vapor recovery units.[154]
- ConocoPhillips installed vapor recovery on nine tank batteries at a total cost of $712,500. The company's investment paid out within less than four months, earning $189,000 per month thereafter.[155]
- Chevron installed eight vapor recovery units on crude oil stock tanks in 1996. This investment paid out in less than one year.[156]

If vapor recovery is not economic, an operator can consider minimizing the operating pressure of its low-pressure separators to reduce flashing losses, or the amount of methane vapors that are flashed off. For example, Devon Energy reported a savings of $7,000 per year after optimizing operating pressures in its low-pressure separators, reducing the amount of methane vapors that are flashed off. The company reported that the "primary goal of the optimization was to increase profits for the facility by putting more gas into the sales pipeline and to reduce emissions of methane with minimal costs to the facility."[157]

4.9.5 Additional Benefits

Vapor recovery units are commonly required in ozone non-attainment areas as lowest achievable emission rate (LAER), or in attainment areas as best available control technology (BACT). Therefore, VRU use to control methane will also have ozone mitigation benefits. Control of tank vent gases can also reduce emissions of HAPs, such as benzene, toluene, ethylbenzene, and xylenes, VOCs, and hydrogen sulfide.

The collection of methane and other gas vapors creates a safer working environment by reducing potentially combustible vapors at the work site.

4.9.6 Limitations and Evaluation

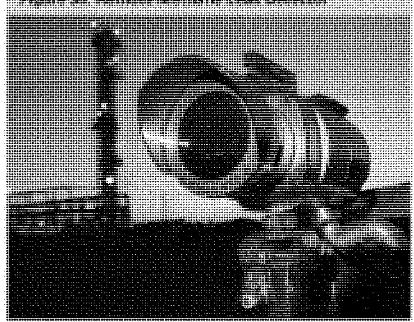
Care must be taken in VRU system design to avoid oxygen entrainment, because oxygen in the system can pose a corrosion and explosion hazard.[158]

VRUs are appropriate for locations that have access to a gas pipeline or an opportunity to use the recovered methane for fuel gas. If this infrastructure does not exist, the technical and economic feasibility may be limited.

Figure 33 illustrates the basic steps for evaluating tank vapor recovery options.

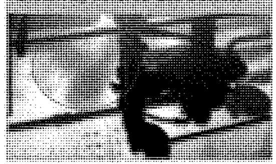
Figure 34: Hand Held Infrared Camera

Figure 35: Remote Methane Leak Detector



© Mine Safety Appliances Co.

Figure 36: Leaking Valve as shown by Infrared Gas Detector



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4.10 LEAK MONITORING AND REPAIR

Methane gas leaks can occur from numerous locations at oil and gas facilities—valves, drains, pumps, threaded and flanged connections, pressure relief devices, open-ended valves and lines, and sample points—as gas moves through equipment under pressure. These leaks are called fugitive emissions.

Fugitive emissions from equipment leaks are unintentional losses of methane gas that may occur due to normal wear and tear, improper or incomplete assembly of components, inadequate material specifications, manufacturing defects, damage during installation or use, corrosion, or fouling.[159]

Because methane is a colorless, odorless gas, leaks often go unnoticed. Historically, checks were typically performed on equipment components when they were first installed, using a soap bubble test or hand held sensor, to ensure the installation was leak tight. After installation, leaks were not typically monitored or repaired unless they became a significant safety hazard. For example, a significant gas leak would be repaired if area, building, or employee monitors set off alarms or if olfactory, audible, or visual indicators observed by facility employees identified the leak. Under these circumstances, the leaks had usually become an obvious safety concern. As a result, methane leaks at outdoor facilities and unmanned facilities often went undetected for long periods of time.

Today, an increasing number of operators are monitoring and repairing leaks at their facilities. Sometimes these programs are instituted voluntarily, other times they are required by the EPA, or state and local air quality control agencies. For instance, the EPA has leak detection and repair regulations for VOCs where facilities meeting certain specifications are required to survey for leaks and repair all detected leaks. A voluntary program, also undertaken by the EPA Natural Gas STAR program, is called Directed Inspection and Maintenance. In this program facilities identify leaks, and then prioritize and repair them based on cost-effectiveness.

4.10.1 Technology Description

Fugitive emission control is a two-part process that includes both a monitoring program to identify leaks and a repair program to fix the leak. Monitoring program type and frequency is a function of the type of component, and how the component is put to use. In most cases, monitoring programs can be intermittently scheduled at a certain frequency (e.g. monthly or quarterly) to identify leaking equipment. However, permanent leak sensors may be required to detect chronic leakers.[160]

There are many different monitoring tools that can be used to identify leaks, including electronic gas detectors, acoustic leak detection systems, ultrasound detectors, flame ionization detectors, calibrated bagging, high volume sampler, end-of-pipe flow measurement, toxic vapor analyzers, and infrared optical gas detectors. A few of these methods are described in more detail to familiarize the reader with the availability of these tools and the ease of measurement capability. Once leaks are identified, the operator can evaluate what is causing the leak and develop a replacement or repair program to mitigate the problem. For example, a hand held infrared camera can be used as a screening tool to detect emissions that are not visible to the naked eye. An infrared camera produces images of gas leaks in real-time. It is capable of identifying methane leaks, but cannot quantify the amount of the leak (Figure 34).

Remote methane leak detectors can detect methane leaks from as far away as 100 feet (Figure 35).

Infrared cameras produce photos that show methane gas leaks, like the leaking valve shown in Figure 36. Once a leak is identified, a more quantitative leak flow rate is needed, and other measurement devices such as high-flow samplers, vent-bag methods, and anemometers may be used.[161] High-flow samplers capture the entire leak, measuring the leak rate directly for leaks up to 10 cubic feet per minute, providing leak flow rate and concentration data.

In 2007, TransCanada reported significant reductions in fugitive emissions by implementing an effective leak monitoring and repair program that included measurement of fugitive emissions using high flow samplers to identify the largest and most effective repairs.[162]

Canadian experience with control of fugitive emissions at oil and gas facilities shows that:[163]

- Most methane leaks are from components in gas service
- Older facilities have the highest leak rates
- About 75 to 85 percent of leaks are economic to repair
- The top 10 leaks at a facility generally contribute more than 80 percent of the emissions

The EPA has found that components in sweet gas service tend to leak more often than those in sour gas service, and a high frequency of leaks occurs from components in vibration, cryogenic, or thermal cycling service.[164]

4.10.2 Opportunity

Reduction Target: 143 Bcf/year

The 2011 *Greenhouse Gas Inventory* estimates that the O&G industry's fugitive emissions are 143 Bcf/year.[165] Elimination or reduction of gas leaks retains more gas in the piping system for sale.

Most large gas processing plants are already subject to the existing NSPS regulations (40 CFR Part 60, Subpart KKK) and required to implement an LDAR program. However, most of the 457,000 miles of production gathering pipelines, and 302,000 miles of transmission pipelines in the United States and 384,000 meters have not been required to implement LDAR programs.[166]

The 143 Bcf/year of fugitive emissions is largely uncontrolled today. Fugitive emissions management is an ongoing commitment, not a one-time initiative. The potential for fugitive equipment leaks will increase as facilities age. Successful fugitive emission control plans require trained personnel, emissions testing equipment, performance tracking systems, and corporate commitment.

4.10.3 Proposed EPA Regulations

The EPA's proposed NSPS regulations would lower leak detection thresholds at gas processing plants.[167] The EPA's proposed NSPS regulations would reduce methane emissions through leak detection and repair by about 0.1 Bcf/year, less than 0.1 percent of the methane emissions from equipment leaks.

Based on the EPA's reported leak monitoring and repair profitability, NRDC recommends that more LDAR programs can and should be required by the EPA. Facilities in all sectors, including the production, transmission and distribution sectors should undertake LDAR programs. Best management practices such as optimizing processes should be used in tandem with LDAR programs. Not all devices that detect VOCs can detect methane, so facilities should specifically employ equipment and processes that can detect methane, such as infrared laser detectors.

4.10.4 Profit

In 2009, the EPA examined the profitability of repairing equipment leaks at oil and gas facilities through a Directed Inspection & Maintenance program.[168]

EPA *Lessons Learned* documents for both gas processing plants and compressor stations show the average cost of repair was between $26,000 and $59,000 per year per facility.[169,170] Methane captured through these programs averaged 30,000 and 87,000 Mcf/year. For gas processing plants, leak screening and monitoring cost about $32,000 annually per plant. At both gas processing plants and compressor stations, the investments are profitable generating as much as $314,000 in profit per facility, with payback periods of just a few months. Additional detail is shown in Appendix A, Table A10.

4.10.5 Additional Benefits

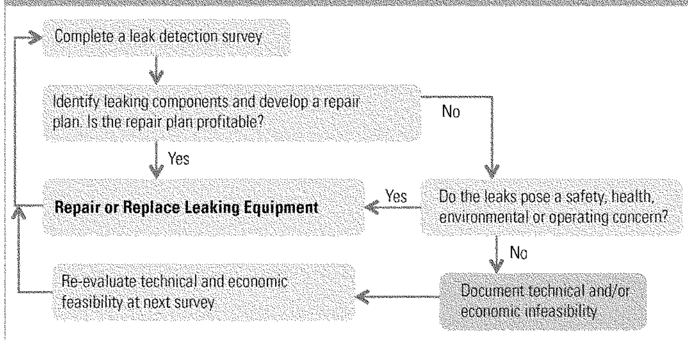
The EPA has found that fugitive emission control provides numerous benefits including: reduced maintenance costs and downtime, improved process efficiency, a safer work environment, a cleaner environment, and resource conservation.[171] Leaking gases may also include toxic air pollutants known to harm human health.

4.10.6 Limitations and Evaluation

There are no major limitations or barriers to implementation of a leak monitoring and repair program.

A simplified evaluation flowchart (Figure 37) is provided to show the basic steps for evaluating leak monitoring and repair.

Figure 37: Leak Monitoring and Repair Evaluation Flowchart



5. CONCLUSION AND POLICY RECOMMENDATIONS

The technologies discussed in this report can be used to reduce significant amounts of methane emissions from the oil and gas production, processing, and transmission sector, while generating significant profits for the O&G Industry. NRDC recognizes that some companies have voluntarily implemented methane controls. Mandatory methane control regulations will be needed for companies that have not updated business-as-usual practices, embraced a culture of environmental responsibility, or chosen to voluntarily invest even in profitable methane control technologies. Through these steps methane can be kept out of the atmosphere and the health and safety of Americans can be improved.

NRDC supports establishing a fully effective system of safeguards to ensure that natural gas is produced, processed, stored, and distributed in a way that ensures protection of our water, air, land, climate, human health, and sensitive ecosystems (For more information on NRDC's position on natural gas and fracking, go to http://www.nrdc.org/energy/gasdrilling/). The use of natural gas in our homes, power plants, and industry also must be as efficient as possible. Americans do not have to trade clean water and clean air for increased natural gas supplies. The O&G industry can and should adopt the methane capture technologies discussed in this report, which are technically proven, commercially available, and profitable.

Given our country's growing reliance on natural gas and methane's strong link to global warming, methane emissions should be controlled to the maximum extent possible. It is fortunate that more than 80 percent of methane emissions could potentially be captured with the technologies highlighted in this report and yield billions of dollars in revenues through sale of the captured methane. Under these circumstances, there is a compelling case for companies to be required to adopt the best methane capture practices as soon as possible, and for government at all levels to take a far more active role in addressing market failures and requiring producers to adopt best practices.

Taking these considerations into account, several policy options can reduce methane emissions across the natural gas industry nationwide. NRDC recommends adoption of the policies outlined below:

- The EPA's proposed NSPS and air toxics standards provide an important starting point for the reduction of air pollutants from O&G operations, with substantial methane co-benefits. Still, there are key ways in which these regulations can be improved, with robust mandates needed, as voluntary programs have proven insufficient. Federal regulations to control methane emissions would need to be adopted by states through their State Implementation Plans. The EPA should:
  - Regulate methane directly
  - Expand its proposal to include emission reduction requirements for existing sources that are the main contributors to VOC and methane emissions from the oil and natural gas industry. States would then be required to adopt methane leakage control measures for existing sources through their State Implementation Plans
  - Ensure coverage of all major methane emission sources for which controls are feasible, including coalbed methane wells and oil wells
  - Strengthen standards where possible. For example, the EPA should raise standards for tank and dehydrator emissions reductions
  - Strengthen required procedures where possible. For example, the EPA should complement its Leak Detection & Repair program by requiring that best management practices be implemented, including process optimization and conducting more frequent leak surveys
- The EPA should continue to improve its mandatory greenhouse gas emissions reporting program for the O&G industry so that methane emission sources can be better identified, and opportunities for reductions can be better targeted. Also, the EPA should provide a more detailed breakdown by source of methane emissions reductions achieved through the Natural Gas STAR program.

- The EPA's Natural Gas STAR program's voluntary framework has encouraged companies to reduce methane emissions and document their reduction activities. Through Natural Gas STAR, techniques to reduce methane emissions have been tried and tested by some companies. Still, many effective reduction technologies have not been widely adopted by industry. To achieve significant industry-wide reductions, the most successful practices documented by the Natural Gas STAR program need to become mandatory. through EPA's regulatory programs such as NSPS and NESHAPs. However, Natural Gas STAR should still play an important role in driving continued improvements that in turn can inform future revisions of EPA standards.
- Federal land management agencies, such as the Bureau of Land Management, should exercise their authority and responsibility to control methane waste from oil and gas lease operations on federal lands. Land management agencies should:
    - Modernize agency policies to prevent waste of methane resources through deployment of all technically and economically viable methane emission reduction technologies and practices, and to establish acceptable performance levels (i.e., levels of emissions beyond which production of mineral resources should be prohibited)
    - Evaluate methane emission risks and reduction opportunities as both a climate and waste problem through planning and environmental reviews before committing resources to development
    - Not commit resources to development where methane emissions cannot technically or economically be abated within acceptable performance levels
    - Where lands are committed to development, mandate specific methane reduction technologies and practices appropriate to the particular production field or geologic formation under consideration
    - Shift the burden to oil and gas lessees and operators to demonstrate, before drilling permits are approved, that all reasonable and prudent methane emission prevention technologies and practices will be used, with land management agencies retaining full authority to mandate specific methane reduction tecbnologies and practices or levels of performance
- States should require the use of methane control technologies. Several gas-producing states have already required methane pollution reduction measures to protect air quality and public health, mostly for large emission sources or in areas of concentrated development. These states, including Colorado, Wyoming, and Montana, provide a good start and model for action by other states and by federal agencies. Exceptions to these rules should be as narrow as possible.

APPENDIX A

The tables in Appendix A provide a detailed economic summary of the 10 methane control technologies. A brief economic summary was also provided in Table 4. The economic analysis in this appendix is presented in a manner that facilitates a ready comparison among reports from various sources. Blank cells indicate insufficient data to compute values.

Where applicable, the economics of the technologies are also compared with the EPA's estimates from its proposed NSPS rulemaking. However, NRDC and other environmental organizations are concerned about potential deficiencies in the EPA's cost-benefit estimates of methane control technologies.[172] Therefore, NRDC has not utilized the EPA's NSPS estimates to inform the range of costs and benefits in this report, and instead has relied heavily on industry data and the EPA's Natural Gas STAR and Methane to Markets data.

Each line in the tables below represents a different data source or a different treatment within a source. Each line includes the source and year of the data (corresponding to the sources cited in the body of this report). The "Type" column describes any feature of the data, such as whether it was an upper bound or an average or based on a particular kind of technology. The next column specifies, if available, the number of devices (or wells or installations) from which an average was obtained. The remaining columns discuss the economics of the technologies.

The terms used in the tables are consistent with common industry and accounting practices:

- Total investment: Total costs of implementing a technology; typically up-front costs, excluding ongoing operating and maintenance expense.
- Annual investment expense: Effective investment cost spread out over the useful life of the investment. In a few tables, for simplicity this is just depreciation expense, using simple depreciation with no salvage value. In other tables where more information is available, this includes joint depreciation and interest expenses using a capital recovery factor.
- O&M expense: Operating and maintenance expense for technology deployment.
- Total annual expense: Annual investment expense plus O&M expenses.
- Revenue from NG: Revenue from the sale of natural gas, obtained by multiplying gas sales volume and price.
- Other revenue: Revenues other than from the sale of natural gas.
- O&M savings: Operating and maintenance savings from technology deployment.
- Total revenue plus savings: Sum of revenue and any O&M savings.
- Payout: Period (in years) in which initial investment is paid back (i.e., total investment divided by total revenues, plus O&M savings, less O&M costs per year).
- Operating profit excluding depreciation: Total revenues, plus O&M savings, less O&M costs, excluding depreciation; akin to EBITDA (earnings before interest, taxes, depreciation and amortization). This is sometimes referred to as "profit" in the text.
- Operating profit: Total revenues, plus O&M savings, less O&M costs, less depreciation (approximated to annual investment expense, as above); akin to EBIT (earnings before interest and taxes).

Table A1: Cost-effectiveness of green completions

Source	Year	Type	# wells	Total investment per well	O&M expense per well	Total expense per well	Volume of saved NG	Price of NG	Revenue from NG	Condensate revenue	Total revenue plus savings per well	Payout	Operating profit (ex depr) per well	Operating profit per well
			#	$	$	$	Mcf / well	$ / Mcf	$ / well	$ / well	$ / well	Years	$ / well	$ / well
EPA Lessons Learned [173]	2011	Purchased equip.	125	4,000[a]	4,850[b]	8,850	10,800[c]	4.00	43,200	7,000[c]	50,200	0.50[d]	45,350	41,350
EPA Lessons Learned [173]	2011	Rented equip.		33,000[e]		33,000	10,800	4.00	43,200	6,930[f]	50,130	immediate	50,130	17,130
EPA [174]	2005	Avg.		14,000		14,000	7,000	4.00	28,000		28,000	immediate	28,000	14,000
Devon Energy [175,176,177]	2004, '05,'07	Avg.	~400[g]	8,700		8,700			50,000		50,000	0.17	50,000	41,300
BP [178,179]	2005, '07	Avg.	106	12,264		12,264	7,500	4.00	30,000	6,321	36,321	0.70	36,321	24,057
Williams [180]	2006	Avg.	1,177	14,444		14,444	22,515	4.00	90,059[h]		90,059	0.16	90,059	75,616
EnCana [181]		Avg.	Many wells									< 1.00		190 M +
Anadarko [182]	2009	Avg.	613					5.00						16,803
ICF [183]	2009	Avg.										0.25		
(EPA NSPS TSD estimates below not utilized to inform the range of costs and benefits in this report; only provided for completeness)														
EPA - NSPS TSD [184]	2008	Min		2,418		2,418								
EPA - NSPS TSD [184]	2008	Max		74,860		74,860								
EPA - NSPS TSD [184]	2008	Avg.		33,237		33,237	8,258[i]	4.00	33,032	2,380	35,412	0.94	35,412	2,175

[a] Based on an investment cost of $500,000, that is spread out over 5 years and 25 well completions per year (does not take into account time value of money).
[b] Based on annual costs of $121,250 spread out over 25 well completions per year.
[c] Volume of saved NG based on 270,000 Mcf saved per year, and condensate revenue based on $175,000 per year, spread out over 25 well completions per year.
[d] Initial investment of $500,000 paid back by operating profit (ex depr) of $45,350 per well x 25 wells per year.
[e] Based on 9 days per well completion and daily costs for contracted services of $3,600 per well per day, plus $600 for initial set-up costs.
[f] Based on 9 days per well completion, 11 barrels of condensates saved per day, valued at $70 per barrel of condensate.
[g] Calculated from estimated average emissions per well, given that total emissions reductions was ~4.8 Bcf in 2005.
[h] Scaled down from revenues based on a historically higher natural gas price, assumed to be $6/Mcf.
[i] 8,258 Mcf of methane: 142.7 tons of methane; production quality natural gas is approx. 83% methane (EPA NSPS TSD page 5-16); 0.0208 tons per Mcf. This is consistent with API's estimate of 8,400 Mcf of methane based on 1.2 Mcf/day for 7 days (API comments to EPA, EPA–HQ–OAR–2010–0505-4266).

Table A2: Cost-effectiveness of plunger lift systems

			#	$	$/yr	Mcf/yr	$/Mcf	$/yr	$/yr	$/yr	Years	$/yr	$/yr
Source	Year	Type	# installations	Total investment	Annual investment expense	Volume of saved NG	Price of NG	Revenue from NG	O&M savings per year[a]	Total revenue plus savings per year	Payout	Operating profit (ex depr) per year	Operating profit per year
EPA Lessons Learned [illegible]	2011	Min		2,600	520[b]	4,700	4.00	18,800	10,900	29,700	0.09	29,700	29,180
EPA Lessons Learned [illegible]	2011	Max		10,400	2,080	18,250	4.00	73,000	10,900	83,900	0.12	83,900	81,820
EPA Lessons Learned [illegible]	2011	Simple Avg		6,500	1,300	11,475	4.00	45,900	10,900	56,800	0.11	56,800	55,500
[illegible]	1997	Avg	19			640	4.00	2,561		2,561		2,561	
BP [illegible]	2007	Avg	2,300			1,424	4.00	5,696					7,095
[illegible]	2008	Avg	1,717	10,000	2,000	13,187	6.00	79,000	24,000	103,000	0.13	103,000	[illegible]

[a] Operational savings here includes maintenance costs less savings such as chemical treatments.
[b] Assumes lifetime of five years for all examples, uses simple depreciation.
[c] Includes savings from avoided electricity, well workovers and chemical treatments.

Table A3: Cost-effectiveness of TEG dehydrator controls

			#	$	$/yr	$/yr	$/yr	Mcf/yr	$/Mcf	$/yr	$/yr	Years	$/yr	$/yr
Source	Year	Type	# devices	Total investment	Annual investment expense	O&M expense per year	Total expense per year	Volume of saved NG	Price of NG	Revenue from NG	Total revenue plus savings per year	Payout	Operating profit (ex depr) per year	Operating profit per year
EPA NG STAR [189,190]	2005	Flash tank separator		5,000	1,000[a]		1,000	3,650	4	14,600	14,600	0.34	14,600	13,600
EPA NG STAR [189,190]	2005	Optimizing glycol circ. Rate						18,250	4	73,000	73,000		73,000	73,000
EPA NG STAR [191]	2007	Rerouting glycol skimmer gas		1,000	200	100	300	7,665	4	30,660	30,660	0.03	30,560	30,360
EPA NG STAR [192]	2007	Installing electric pump		7,000[b]	1,400		1,400	5,000[c]	4	20,000	20,000	0.35	20,000	18,600
EPA NG STAR [193]	2005 –07	All four above	4	13,000	2,600	100	2,700	34,565	4	138,260	138,260	0.09	138,160	135,560

[a] Assumes lifetime of five years for all examples, uses simple depreciation.
[b] Approximate average of a range of costs from $1,400 to $13,000.
[c] Conservative estimate based on the EPA range (360 Mcf/year to 36,000 Mcf/year).

Table A4: Cost-effectiveness of desiccant dehydrators

			#	$	$ / yr	Mcf	$ / Mcf	$ / yr	$ / yr	$ / yr	Years	$ / yr	$ / yr
Source	Year	Type	# devices	Total investment	Annual investment expense	Volume of saved NG	Price of NG	Revenue from NG	O&M savings per year	Total revenue plus savings per year	Payout	Operating profit (ex depr) per year	Operating profit per year
EPA NG STAR [illegible]	[illegible]	Avg.		16,000	3,200[a]	1,000	4	4,000	2,000	6,000	2.67	6,000	2,800
BP [illegible]	[illegible]	Avg.	[illegible]								[illegible]		3,147[b]

[a] Assumes lifetime of five years, uses simple depreciation.
[b] Based on reported profit of $27 million. Assumes a lifetime of 10 years. $3,147 is the operating profit per device per year (including annual investment expense) over the period of 10 years.

Table A5: Cost-effectiveness of replacing wet seals in centrifugal compressors with dry seals

			#	$	$ / yr	Mcf	$ / Mcf	$ / yr	$ / yr	$ / yr	Years	$ / yr	$ / yr
Source	Year	Type	# devices	Total investment	Annual investment expense	Volume of saved NG	Price of NG	Revenue from NG	O&M savings per year	Total revenue plus savings per year	Payout	Operating profit (ex depr) per year	Operating profit per year
EPA Lessons Learned [196]	2006	Avg.		324,000	46,129[a]	45,120	4	180,480	102,400	282,880	1.15	282,880	236,751
EPA NG STAR [197,198]	2006	Max (savings)		324,000	46,129	100,000	4	400,000[b]	120,000[c]	520,000	0.62	520,000	473,871
Petroleos Mexicanos [199]	2008	Avg.				35,000	4	140,000		140,000+		140,000+	
Targa [200]	2006	Avg.		90,000	12,814					300,000	0.38[d]	300,000	287,186
(EPA NSPS TSD estimates below not utilized to inform the range of costs and benefits in this report; only provided for completeness)													
EPA – NSPS TSD [201]	2008	Processing		75,000[e]	10,678[f]	11,527[g]	4	46,108	88,300	134,408	0.56	134,408	123,730
EPA – NSPS TSD [201]	2008	Trans. / Storage		75,000	10,678	6,372[g]			88,300	88,300	0.85	88,300	77,622
EPA – NSPS TSD [201]	2008	Simple avg.		75,000	10,678	8,949		23,054	88,300	111,354	0.67	111,354	100,676

[a] For annual investment expense including joint depreciation and interest expenses, assumes similar lifetimes and discount rate as in the EPA's NSPS estimates.
[b] Illustrative high-end estimate of natural gas savings based on the range of savings from $75,000 - $400,000
[c] Average maintenance and operational savings of $120,000 based on the range of savings of $100,000 - $140,000.
[d] Average of 2 – 7 months.
[e] The EPA reports this to be 1-3% of the total pipeline cost. This is the incremental cost of a compressor with a dry seal instead of one with a wet seal (EPA NSPS TSD, page 6-19).
[f] The EPA assumes a 10-year lifetime and a 7% discount rate; here annual investment expense includes joint depreciation and interest expenses.
[g] EPA NSPS TSD, page 6-20, Table 6-8, based on individual compressor emissions reductions in tons per year.

Table A6: Cost-effectiveness of replacing rod packing in reciprocating compressors

			#	$	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Source	Year	Type	# devices	Total investment	Annual investment expense	Volume of saved NG	Price of NG	Revenue from NG	Total revenue plus savings per year	Payout	Operating profit (ex depr) per year	Operating profit per year
EPA Lessons Learned [illegible]	2008	Avg		6,480[a]	2,493[b]	[illegible]	4	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
JFT [illegible]	2008	Avg		4,800[c]	[illegible]	[illegible]	4	14,016	14,016	0.34	14,016	[illegible]
(EPA NSPS TSD estimates below not utilized to inform the range of costs and benefits in this report; only provided for completeness)												
EPA – NSPS TSD [204]	2008	Production		6,480	2,493[e]	9[f]	4	36	36	180.00	36	(2,457)
EPA – NSPS TSD [204]	2008	Gathering, Boosting		5,346	1,669[e]	396[f]	4	1,584	1,584	3.38	1,584	(85)
EPA – NSPS TSD [204]	2008	Processing		4,050	1,413[e]	1,077[f]	4	4,308	4,308	0.94	4,308	2,895
EPA – NSPS TSD [204]	2008	Transmission		5,346	1,669[e]	1,257[f]			0	NA	0	(1,669)
EPA – NSPS TSD [204]	2008	Storage		7,290	2,276[e]	1,263[f]			0	NA	0	(2,276)
EPA – NSPS TSD [204]	2008	Simple avg.		5,702	1,904	296	4	1,186	1,186	4.81	1,186	(718)

[a] Cost of replacing rod packing for four cylinders (as per EPA TSD estimate of average number of reciprocating compressor cylinders in the production sector, Table 6-2), at $1,620 per cylinder.
[b] For annual investment expense including joint depreciation and interest expenses, assumes similar lifetimes and discount rate as in the EPA's NSPS estimate for reciprocating compressors in the production sector, i.e., same capital recovery factor (EPA NSPS TSD Table 6-7 and page 6-16).
[c] Cost of replacing rod packing for four cylinders (as per EPA TSD estimate of average number of reciprocating compressor cylinders in the production sector, Table 6-2), at $1,200 per cylinder.
[d] Multiplying estimated emissions savings as reported by sources by four, to account for savings from four cylinders.
[e] The EPA annual investment expense estimates include joint depreciation and interest expenses, but uses slightly different capital recovery factors for different kinds of devices (EPA NSPS TSD Table 6-7 and page 6-16).
[f] EPA NSPS TSD, page 6-15, Table 6-6; based on individual compressor emissions reductions in tons per year.

Table A7: Cost-effectiveness of replacing high-bleed pneumatic controllers with low-bleed pneumatic controllers

Source	Year	Type	# devices	Total investment cost	Annual investment expense	Volume of saved NG	Price of NG	Revenue from NG	O&M savings per year	Total revenue plus savings per year	Payout	Operating profit (no depr) per year	Operating profit per year
			#	$	$/yr	Mcf	$/Mcf	$/yr	$/yr	$/yr	Years	$/yr	$/yr
EPA [illegible]	[illegible]	Avg.		350[a]	[illegible]	180	4	720	1,100	1,820	0.19	[illegible]	[illegible]
EPA Lessons Learned [illegible]	[illegible]	Avg.		[illegible]	[illegible]	[illegible]	4	500	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
BP [illegible]	[illegible]	Avg.	11,500	174	[illegible]	[illegible]	4	1,163	[illegible]	[illegible]	0.09	[illegible]	[illegible]

(EPA NSPS TSD estimates below not utilized to inform the range of costs and benefits in this report; only provided for completeness)

Source	Year	Type	# devices	Total investment cost	Annual investment expense	Volume of saved NG	Price of NG	Revenue from NG	O&M savings per year	Total revenue plus savings per year	Payout	Operating profit (no depr) per year	Operating profit per year
EPA - NSPS TSD [210]	2008	Min		158	23[h]								
EPA - NSPS TSD [210]	2008	Max		1,852	264								
EPA - NSPS TSD [210]	2008	Avg.		165	24	375[i]	4	1,500		1,500	0.11	1,500	1,477

[a] Based on incremental cost of fitting low-bleed devices instead of low-bleed devices, for all lines.
[b] For annual investment expense including joint depreciation and interest expenses, assumes similar lifetimes and discount rate as in the EPA's NSPS estimates.
[c] Based on average natural gas savings of 0.5 Mcf/day (as reported in sources).
[d] Average of $210 and $340 per device.
[e] Average of 50 and 200 Mcf/year.
[f] Assumes half of replacement cost.
[g] 11,500 wells saved 3.4 Bcf/year.
[h] The EPA assumes a lifetime of 10 years and a discount rate of 7% (NSPS TSD page 5-16, 5-17); here annual investment expense includes joint depreciation and interest expenses.
[i] Using the average value of dollar savings (NSPS TSD page 5-16); calculated natural gas volume is consistent with TSD value quoted.

Table A6: Cost-effectiveness of replacing high-bleed pneumatic controllers with instrument- air pneumatic controllers

Source	Year	Type	# devices	Total investment	Annual investment expense	O&M expense per year	Total expense per year	Volume of saved NG	Price of NG	Revenue from NG	Total revenue plus savings per year	Payout	Operating profit (ex dept) per year	Operating profit per year
			#	$	$/yr	$/yr	$/yr	Mcf	$/Mcf	$/yr	$/yr	Years	$/yr	$/yr
[illegible]	[illegible]	Avg		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	4	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	Avg		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	4	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
(EPA NSPS TSD estimates below not utilized to inform the range of costs and benefits in this report; only provided for completeness)														
EPA - NSPS TSD [214]	2008	Small		16,972	2,416[d]	1,334	11,090[e]	871	4	3,484	3,484	NA	(5,190)	(7,606)
EPA - NSPS TSD [214]	2008	Med		73,531	10,469	4,333	36,877	3,658	4	14,632	14,632	NA	(11,776)	(22,245)
EPA - NSPS TSD [214]	2008	Large		135,750	19,328	5,999	80,515	10,161	4	40,644	40,644	NA	(20,543)	(39,871)
EPA - NSPS TSD [214]	2008	Simple avg.		75,418	10,738	3,889	42,827	4,897	4	19,587	19,587	NA	(12,503)	(23,241)

[a] For annual investment expense including joint depreciation and interest expenses, assumes similar lifetimes and discount rate as in the EPA's NSPS estimates.
[b] Includes both labor and operational costs such as electrical power (unlike EPA costs in same column).
[c] Range between calculated value and reported value.
[d] EPA assumes a 10-year life, and a 7% discount rate; here annual investment expense includes joint depreciation and interest expenses.
[e] The total expense includes capital, labor and electrical power.

Table A3: Cost-effectiveness of installing vapor recovery units

			#	$	$/yr	$/yr	$/yr	Mcf	$/Mcf	$/yr	$/yr	Years	$/yr	$/yr
Source	Year	Type	# devices	Total investment	Annual investment expense	O&M expense per year	Total expense per year	Volume of saved NG	Price of NG	Revenue from NG	Total revenue plus savings per year	Payout	Operating profit (ex depr) per year	Operating profit per year
EPA NG STAR [16]	2010	Small		35,738[a]	3,924[b]	7,367	11,291	4,546	4	18,184	18,184	3.28	10,896	6,972
EPA NG STAR [16]	2010	Med.		56,524	6,086[b]	10,103	16,189	18,262	4	73,048	73,048	0.88	62,945	56,859
EPA NG STAR [16]	2010	Large		103,858	11,414[b]	16,839	28,253	81,311	4	325,244	325,244	0.38	340,483	329,069
EPA NG STAR [16]	2010	Simple avg.		65,374	7,145[b]	11,436	18,581	38,046	4	152,184	152,184	0.46	140,748	133,603
Anadarko [17]	1998	Avg.	300										4,167	
ConocoPhillips [18]		Avg.	8	78,167	8,692[b]							0.30	252,000	243,308
Chevron [19]	1996	Avg.	8									<1		

(EPA NSPS TSD estimates below not utilized to inform the range of costs and benefits in this report; only provided for completeness)

EPA – NSPS TSD [219]	2008	Avg.		98,186	10,780[d]	9,367	20,147	291	4	1,164	1,164	NA	(8,203)	(18,983)

[a] This includes capital cost and installation cost equal to 75% of the capital cost.
[b] For annual investment expense including joint depreciation and interest expenses, assumes similar lifetimes and discount rate as in the EPA's NSPS estimates.
[c] Scaled down from savings based on a historically higher natural gas price of $6.22/Mcf.
[d] EPA assumes a 15-year life and a 7% discount rate; here annual investment expense includes joint depreciation and interest expenses.

Table A10: Cost-effectiveness of leak monitoring and repair systems

			#	$/yr	$/yr	$/yr	Mcf	$/Mcf	$/yr	$/yr	Years	$/yr	$/yr
Source	**Year**	**Type**	**# devices**	**Total investment per year**	**O&M expense per year**	**Total expense per year**	**Volume of saved NG**	**Price of NG**	**Revenue from NG**	**Total revenue plus savings per year**	**Payout**	**Operating profit (ex depr) per year**	**Operating profit per year**
EPA Lessons Learned [220]	2003	Gas processing plants		59,000[a]	32,000[b]	91,000	86,500[c]	4	346,000	346,000	0.19	314,000	255,000
EPA Lessons Learned [221]	2003	Compressor stations		26,200		26,200	29,400	4	117,600	117,600	0.22	117,600	91,400
Methane to Markets [222]	2009	Valves		130			2,895	4	11,580	11,580	likely small		likely positive
Methane to Markets [222]	2009	Connectors		10			3,482	4	13,928	13,928	likely small		likely positive
Methane to Markets [222]	2009	Open ended lines		60			2,320	4	9,280	9,280	likely small		likely positive
Methane to Markets [222]	2009	Simple avg.		67			2,899	4	11,596	11,596	likely small		likely positive
Canadian experience [223]	2005	Avg.									small		positive
(EPA NSPS TSD estimates below not utilized to inform the range of costs and benefits in this report; only provided for completeness)													
EPA - NSPS TSD [224]	2008	Valves		18,529[d]	incl. in total	34,608	1,060[d]	4	4,241	4,241	NA	negative	(30,366)
EPA - NSPS TSD [224]	2008	Connectors		9,991	incl. in total	25,622	515	4	2,061	2,061	NA	negative	(23,561)
EPA - NSPS TSD [224]	2008	Pressure Relief Devices		101,820	incl. in total	40,372	160	4	639	639	NA	negative	(39,734)
EPA - NSPS TSD [224]	2008	Open ended lines		12,280	incl. in total	26,200	693	4	2,772	2,772	NA	negative	(23,428)
EPA - NSPS TSD [224]	2008	Simple avg.		35,655	incl. in total	31,700	607	4	2,428	2,428	NA	negative	(29,272)

[a] Average of $39,000 and $78,000 for repairs annually.
[b] Average of $14,000 and $50,000 for leak screening and measurement annually.
[c] Average of 45,000 and 128,000 Mcf/year per gas plant.
[d] Average of values from Tables 8-14, 8-15 and 8-17. Table 8-16 data was not included as that was only incremental cost data.

APPENDIX B: LIST OF ACRONYMS

API	American Petroleum Institute
AQ	Air Quality
BACT	Best Available Control Technology
BAT	Best Available Technology
bbl	Barrels (equivalent to 42 gallons)
Bcf	Billion standard cubic feet
Bcf/year	Billion standard cubic feet per year
BMP	Best Management Practices
bopd	Barrels of oil per day
BTU	British Thermal Unit
CDA	Concentrated Development Area
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide equivalent
DEG	Diethylene Glycol
DOE	U.S. Department of Energy
E&P	Exploration & Production
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
GRI	Gas Research Institute
GWP	Global Warming Potential
HAPs	Hazardous Air Pollutants
HFCs	Hydrofluorocarbons
IPCC	Intergovernmental Panel on Climate Change
JPAD	Jonah-Pinedale Anticline Development Area
KWh	Kilowatt-hour
LAER	Lowest Achievable Emission Rate
LDAR	Leak Detection & Repair
MEG	Ethylene Glycol
Mt	Metric ton (equivalent to 1.102 short tons)
MMt	Million Metric tons
$MMtCO_2e$	Million Metric tons of Carbon Dioxide equivalent
Mcf	Thousand standard cubic feet
MMcfd	Million standard cubic feet per day
NAAQS	National Air Ambient Air Quality Standards
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NO_x	Nitrogen Oxides
NPV	Net Present Value
NRDC	Natural Resources Defense Council
NSPS	New Source Performance Standards
O&G	Oil & Gas
O&M	Operations & Maintenance
P&A	Plug & Abandonment
PM	Particulate Matter
PROs	Partnership Reduction Opportunities
PRV	Pressure Relief Valve
psi	Pounds per square inch
REC	Reduced Emission Completion
scf	Standard cubic feet
scfm	Standard cubic feet per minute
TEG	Triethylene Glycol
tpy	Tons per year
TREG	Tetraethylene Glycol
TSD	Technical Support Document
TWG	Technical Work Group
U.S.	United States
VOCs	Volatile Organic Compounds
VRU	Vapor Recovery Unit
WCI	Western Climate Initiative
WGA	Western Governors Association
WRAP	Western Regional Air Partnership

APPENDIX C : METHANE EMISSION SOURCE DETAIL

Table C1: Natural Gas System Methane Emission Sources

2009 NATURAL GAS SYSTEMS METHANE EMISSIONS			TECHNOLOGY OPTIONS COVERED IN PAPER	PERCENT OF OVERALL EMISSIONS
	Bcf	Bcf		%
PRODUCTION	**464**			
Well Completion, Workovers		68.26	No. 1 Green Completions	10%
Well Clean Ups (Low pressure gas wells)		236.47	No. 1 & 2 Green Completions and Plunger Lifts	33%
Dehydrator Vents		5.81	No. 3 & 4 Dehydrator Controls	1%
Reciprocating Compressors		4.33	No. 6 Improved Compressor Maintenance	1%
Pneumatic Controllers		62.92	No. 7 Low -Bleed or No-Bleed Controllers	9%
Pipeline Emissions		0.15	No. 8 Pipeline Maintenance and Repair	0%
Tank Venting		7.04	No. 9 Vapor Recovery Units	1%
Controlled Tank Vents		1.41		0%
Heaters		1.83		0%
Separators		5.85		1%
Vessel & Compressor Blowdown & Mishaps		0.29		0%
Compressor Starts		0.31		0%
Coal Bed Methane		3.59		1%
Engine & Turbine Exhaust		14.35		2%
Pump Emissions		17.18		2%
Offshore		15.67		2%
Fugitive Emissions		18.28	No. 10 Leak Monitoring and Repair	3%
Subtotal		**463.73**		
Subtotal of Emissions Controllable by the 10 Technologies		**403.26**		
PROCESSING	**48**			
Dehydrator Vents		1.39	No. 3 & 4 Dehydrator Controls	0%
Centrifugal Compressors Wet Seals		12.12	No. 5 Dry Seal Systems	2%
Centrifugal Compressors Dry Seals		1.28		0%
Reciprocating Compressors		19.93	No. 6 Improved Compressor Maintenance	3%
Pneumatic Controllers		0.10	No. 7 Low -Bleed or No-Bleed Controllers	0%
Pipeline Emissions		1.17	No. 8 Pipeline Maintenance and Repair	0%
Tank Venting		1.17	No. 9 Vapor Recovery Units	0%
Engine & Turbine Exhaust		8.64		1%
Acid Gas Removal Vents		0.65		0%
Pump Emissions		0.23		0%
Fugitive Emissions		1.67	No. 10 Leak Monitoring and Repair	0%
Subtotal		**48.35**		
Subtotal of Emissions Controllable by the 10 Technologies		**37.54**		

Table C1: Natural Gas System Methane Emission Sources *(Continued)*				
TRANSMISSION	**129**			
Dehydrator Vents		0.34	No. 3 & 4 Dehydrator Controls	0%
Centrifugal Compressors Wet Seals		14.42	No. 5 Dry Seal Systems	2%
Centrifugal Compressors Dry Seals		0.98		0%
Reciprocating Compressors		51.25	No. 6 Improved Compressor Maintenance	7%
Pneumatic Controllers		13.93	No. 7 Low -Bleed or No-Bleed Controllers	2%
Pipeline Emissions		17.35	No. 8 Pipeline Maintenance and Repair	2%
Tank Venting		1.71	No. 9 Vapor Recovery Units	0%
Engine & Turbine Exhaust		13.71		2%
Fugitive Emissions		15.18	No. 10 Leak Monitoring and Repair	2%
Subtotal		**128.87**		
Subtotal of Emissions Controllable by the 10 Technologies		**114.17**		
DISTRIBUTION	**74**			
Pipeline Emissions		0.13	No. 8 Pipeline Maintenance and Repair	0%
Fugitive Emissions (Pipeline and Meter Leaks)		71.55	No. 10 Leak Monitoring and Repair	10%
Pressure Relief Valves & Mishaps (Dig-ins)		2.15		0%
Subtotal		**73.84**		
Subtotal of Emissions Controllable by the 10 Technologies		**71.69**		
TOTAL	**715**			
Total of Emissions Controllable by the 10 Technologies		**627**		88%
Other Emissions		**88**		12%

Source: U.S. EPA 2011 *Greenhouse Gas Inventory* Conversion: Gg/19.26=Bcf

Table C2: Petroleum System Methane Emission Sources				
[illegible] PETROLEUM SYSTEM METHANE EMISSIONS			TECHNOLOGY OPTIONS COVERED IN PAPER	PERCENT OF TOTAL EMISSIONS
	Bcf	Bcf		%
PRODUCTION	**75**			
Pneumatic Controller		21.75	No. 7 Low-Bleed or No-Bleed Controllers	29%
Tank Venting		11.01	No. 9 Vapor Recovery Units	14%
Fugitive Emissions		37.33	No. 10 Leak Monitoring and Repair	49%
Combustion and Process Upsets		4.88		6%
Subtotal		74.97		
Subtotal of Emissions Controllable by the 10 Technologies		70.09		
TRANSMISSION	**0**			**0%**
REFINING	**1**			**2%**
TOTAL	**76**			
Total of Emissions Controllable by the 10 Technologies				92%
Other emissions				8%

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FOLLOW-UP QUESTIONS FOR WRITTEN SUBMISSION

HEARING ON
"FUGITIVE METHANE EMISSIONS FROM OIL AND GAS OPERATIONS"
BEFORE THE COMMITTEE ON ENVIRONMENT & PUBLIC WORKS
SUBCOMMITTEE ON OVERSIGHT
U.S. SENATE
NOVEMBER 5, 2013

Dr. Vignesh Gowrishankar
Staff Scientist
Natural Resources Defense Council

Questions from Senator Barbara Boxer

1. The University of Texas study entitled "Measurements of methane emissions at natural gas production sites in the United States," Proceedings of the National Academy of Sciences (October 29, 2013) ("UT Study") found that 33% of the surveyed well completions at sites that were selected by the nine natural gas companies did not use reduced emission completions (REC) to control well flow back emissions. The Environmental Defense Fund's "FAQ About the University of Texas Methane Study" states that these non-REC wells "had low initial gas production compared to the controlled wells" and that "the wells with uncontrolled releases had much lower than average potential to emit." Given the industry selection of the sites and the lower emitting potential of these uncontrolled, non-REC wells, does the collected data allow for any type of rigorous conclusions about the current national level of REC utilization or the methane emission rates from uncontrolled well sites that were not surveyed as part of the study?

In this context, the UT Study collected data from 27 wells in different regions and with different operational and emissions profiles. As noted in the question, nine of these wells did not use RECs as they were expected to have lower initial gas production. 27 wells represent a small fraction of the roughly half-million natural gas wells in the US. Also, these wells are operated by a few companies that are partnering with UT in this study, and, as such, are not representative of the operations of a large number of other natural gas companies.

Accordingly, the UT Study data does not allow extrapolation to a national level of either the level of REC utilization or emission rates of wells that do not utilize RECs. As for the level of REC utilization, this is currently difficult to gauge due to the lack of coordinated reporting. However, completion emissions from many gas wells may be expected to be suitably controlled by 2015 as per EPA's 2012 new source performance standards. While the UT Study found that the third of the well sites in their study that did not use RECs may have had low potential emissions rates, I am not aware of any data supporting an extrapolation of that percentage to the well population nationwide. Additional research and data are needed to characterize on a national basis both the range of potential emissions rates from uncontrolled well sites and the percentage of wells that have very low potential emissions rates.

2. Several other peer reviewed studies have analyzed the methane emission rates associated with oil and gas drilling and found the emission rates to be significantly higher than emission rates derived from the data collected in the UT Study. Does the UT Study invalidate the findings of the following two peer reviewed studies? If your answer is in the affirmative, please provide the published peer review literature other than the UT Study that supports such a conclusion.

- *Anna Karion, et al (2013) "Methane emissions estimate from airborne measurements over a western United States natural gas field," Geophysical Research Letters Volume 40, Issue 16, pages 4393-4397.*

- *J. Peischl, et al. (2013) "Quantifying sources of methane using light alkanes in the Los Angeles basin, California," Journal of Geophysical Research: Atmospheres, Volume 118, Issue 10, pages 4974-4990.*

The UT Study is a rigorous study of a limited set of wells and equipment during the extraction and production of natural gas. It is fundamentally a "bottom-up" study, which aggregates leakage by multiplying the number of wells, compressors and other pieces of equipment, by assumed or measured leakage rates. This particular study throws light on only the first step of the natural gas supply chain – extraction and production. Furthermore, the small sample set is not representative of operations across the country.

In contrast, the two studies referenced in the question use a "top-down" approach that measures actual methane pollution in the atmosphere and attributes it to natural gas operations. Accordingly, such an approach provides a reality check on possible shortcomings with traditional "bottom-up" approaches, which may have overlooked significant leakage sources and/or used outdated assumptions. These "top-down" studies may also include emissions from outside the extraction and production step, such as processing and storage. The two studies referenced here are for specific oil and/or natural gas producing regions in Utah and California, respectively. A third recent study[1] of atmospheric methane emissions with a national focus has also indicated that methane emissions from oil and gas operations could be much higher than reported by the latest EPA inventory.

The different studies do not invalidate each other by any means, but they do raise important questions as to why there is a wide discrepancy in the emissions suggested by them. Further emissions measurements of different kinds need to be continued, and their results dissected and analyzed, to develop a truly representative picture of the emissions profile of the oil and natural gas industry at a national level.

Nonetheless, that should not delay us from acting now. We already know that methane emissions are a significant problem, and technically feasible and cost-effective solutions are available to stem this pollution. We need strong standards to ensure that such pollution is curbed industry-wide.

[1] Scot M. Miller et al., Anthropogenic emissions of methane in the United States, PNAS 2013; published ahead of print November 25, 2013, doi:10.1073/pnas.1314392110.

3. EPA's New Source Performance Standards for Oil and Gas Production do not currently contain requirements to control the emissions from many types of emissions control equipment used at oil and gas wells. Would the establishment of standards for pneumatic devices at wells, pressure relief valves at storage tanks, and the compressors and pressurized motors used to move natural gas through processing plants and pipelines reduce VOC, methane and other emissions?

Yes, the establishment of standards for other equipment at oil and gas wells and elsewhere in the supply chain would appreciably reduce VOC, methane and other emissions.

Based on internal estimates using EPA 2013 inventory data,[2] we think that the EPA standards will reduce approximately only 10-15 percent[3] of the industry's total annual emissions in the near-term. As old equipment is replaced over time and new equipment becomes subject to the standards, by 2035, annual emissions reductions could increase to approximately 25-30 percent of the total.[4]

Therefore, in order to be more effective, all significant emissions sources, and both existing and new sources of emissions, must be controlled.

During the extraction and production steps in particular, aside from well emissions, the major sources of emissions include pneumatic controllers, equipment leaks, storage tanks, compressors and pumps. These could constitute upwards of one third of potential emissions. Therefore, requiring standards for such equipment could significantly reduce emissions.

Across the entire natural gas supply chain, the major sources are similar to those above. As per estimates based on our Leaking Profits[5] report, requiring standards for this equipment, along with controls for well emissions, could address and potentially reduce a high percentage of total emissions, in the vicinity of 60-75 percent.[6]

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[2] EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2011, April 2013, available at http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html. Emissions reductions from sources that will be controlled by EPA's standards are aggregated, and divided by total annual emissions to calculate percentage emissions reductions. Emissions reductions primarily include reductions from well completions, certain new pneumatic controllers, compressors and storage vessels, and equipment at new gas processing plants. This assumes reasonable turnover rates for equipment, and looks at years immediately following full implementation of the standards.

[3] This number would depend on the size of the total emissions inventory (noting that there has been and continues to be uncertainty in these emissions), as well as other factors such as the technical applicability of the standards, exemptions and enforcement.

[4] James Bradbury, Michael Obeiter, Lauren Draucker, Wen Wang, Amanda Stevens, Clearing the Air: Reducing Upstream Greenhouse Gas Emissions from U.S. Natural Gas Systems, published by World Resources Institute, April 2013, available at http://www.wri.org/publication/clearing-air. This report was based on EPA's Inventory published in 2012, but the results are roughly similar after making adjustments using EPA's 2013 Inventory data.

[5] Susan Harvey, Vignesh Gowrishankar and Thomas Singer, Leaking Profits: The U.S. Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste, published by NRDC, April 2012, available at http://www.nrdc.org/energy/leaking-profits.asp.

[6] Leaking Profits was based on EPA's Inventory published in 2011, and estimated that more than 80 percent of emissions could be addressed and potentially controlled by ten technically feasible and cost-effective technologies.

Accordingly, NRDC recommends that the federal government require the following additional measures to reduce methane emissions further:

- Controls for existing equipment (not just new or modified ones), particularly existing compressors and pneumatic controllers, for which reducing emissions is particularly cost-effective.
- Green completions (or other emission control practices) for associated or co-producing wells, which produce both oil and gas.
- Plunger lift systems (or similar approaches) at existing gas- or oil-producing wells that vent methane during clean-up operations.
- Rigorous leak detection and repair protocols that are able to detect a variety of leaks, efficiently over the numerous sources within the oil and gas industry, and repair them effectively and in a timely fashion.
- A suite of emission control measures that apply to the downstream portion of the natural gas supply chain where gas is stored, transported and piped to residential, commercial and industrial end-users. This includes leak detection and repair of corroded and leaky pipelines; replacement of leaking pneumatic controllers, compressors and other components; and the use of smart pipeline repair techniques that vent less methane.

4. EPA's New Source Performance Standards for Oil and Gas Production do not contain requirements to control the completion and production emissions from wells that co-produce oil and natural gas. Do such co-produced wells release VOCs, methane and other emissions that can be controlled through reduced emission completions and other readily available technologies?

Yes, co-producing wells do release VOCs, methane and other emissions that can be significantly controlled through the use of reduced emissions completions and other available technologies.

As a clarification, the EPA's New Source Performance Standards apply to (onshore) wells drilled principally for production of natural gas. It is therefore presumed that the standards would not typically apply to oil wells that are drilled principally for the production of oil, although they would apply to co-producing wells that are drilled principally for the production of gas.

Attempting to classify any particular well as an "oil" or "gas" well can be misleading, particularly in unconventional formations, as so-called "oil" wells will also produce gases such as methane, VOCs and other pollutants. The amount and proportions of these gases will vary widely, depending on region, type of source rock and operational details. Therefore, the use of reduced emissions completions or other equipment to capture the gas, for sale, onsite use or flaring, would reduce atmospheric release of these gases. Even in the case of co-producing wells the use of green completions can be cost-effective.[7]

Making minor adjustments based on the most recent EPA Inventory published in 2013, relevant technologies discussed in Leaking Profits could still be able to address and potentially control 60-75 percent of total emissions.

[7] Memorandum titled "Methods Memo on VOC Cost-Effectiveness in Controlling Bakken Shale Combined Oil and Gas Wells During Well Completion", prepared by Leland Deck, Stratus Consulting for Environmental Defense Fund, submitted to EPA New Source Performance Standards proposed rule docket on April 2, 2012, docket reference number EPA-HQ-OAR-2010-0505-4490.

<u>Questions from Senator David Vitter</u>

1. Dr. Gowrishankar, in your "Leaking Profits" study did you review the technical feasibility of all the control technologies you recommended? If not, how is it possible to make claims they are cost effective if some of them can't be deployed?

The ten technologies that were discussed in Leaking Profits are indeed technically feasible and commercially viable technologies. The principal author of the report is an oil and gas consultant with over 25 years of experience as a petroleum and environmental engineer. In addition, the report referred to numerous technical documents, including those published in academic peer-reviewed journals and by the U.S. EPA. The report also referred to presentations and documents by companies that had used these technologies in the field and had found them to be effective in reducing emissions, while generating net revenue. The ten technologies were chosen for their combination of technical feasibility, commercial viability based on actual use, and potential to cut emissions. Accordingly, we are confident that the technologies are technically feasible and commercially viable.

2. Do you acknowledge that there is a major difference between the amount of natural gas a company will allow to flow back when using a green completion as opposed where no green completion is being used and gas is simply being emitted into the atmosphere?

Based on my interpretation of the question as written above, yes, there is a difference between the amount of natural gas that is leaked into the atmosphere with and without the use of green completions. With the use of green completions, it has been shown that easily more than 95 percent of emissions from the flowback that would be otherwise leaked into the atmosphere can be captured or controlled. Without the use of green completions, the amount of gas emitted into the atmosphere would depend on the well and hydraulic fracturing characteristics, but would likely be much larger than in the previous case. Therefore, we strongly support EPA's 2012 new source performance standards that require the use of green completions.

3. How do you personally distinguish between a "benefit" and a "co-benefit?" If the "co-benefit" greatly outweighs the "benefit" at what point is a regulation actually about what might be labeled a "co-benefit?"

A particular standard may have "benefits" and "co-benefits" that happen alongside. For regulatory purposes, a "benefit" is a positive effect of the standard directly tied to the statutory obligation the standard fulfills (e.g., control of a target pollutant), while a "co-benefit" is an additional positive effect of the standard. A complete regulatory impact assessment will capture both benefits and co-benefits.

In the case of emissions from the natural gas industry, significant public health and environmental harms are caused by the emissions of pollutants that are regulated under three different programs – volatile organic compounds (VOCs), hazardous air pollutants (HAPs), and methane, a greenhouse gas with at least 25 times the heat-trapping potency of carbon dioxide.

Reducing the leakage of all these pollutants creates benefits for public health and the environment. To date, EPA has directly regulated VOCs in its 2012 new source performance standards, alongside which it also promulgated hazardous air pollutant standards for HAPs. The Clean Air Act's Section 111, however, also requires regulation of methane from the oil and gas sector. When EPA fulfills that legal obligation, methane reductions that EPA currently counts as a "co-benefit" of VOC and HAP standards will be treated as a direct benefit.

4. You mention in your testimony that NRDC's top institutional priority is curbing global warming and building the clean energy future.

> *a) How many legal challenges to renewable energy projects has NRDC been a party to since this became the group's "top institutional priority?"*
> *b) Can you identify any countries who have successfully built a "clean energy future" whose lead the United States should follow?*
> *c) Does NRDC consider nuclear energy as part of a "zero-emissions sources" future?*

a) NRDC is a strong supporter of well-sited renewable energy. NRDC has been party to one legal challenge to one renewable energy project in the last five years, and the case was first put on hold and then dropped because the developer chose not to proceed with the project. NRDC has also helped to defend a renewable energy project that was challenged in court by opponents.

b) The United States is already a leader in clean energy technology innovation, and we should never accept follower status. The clean energy economy is the fastest growing part of our energy economy, and we can and should lead the world to a cleaner, healthier, more prosperous future. Of course we can learn lessons from the renewable energy successes that countries such as Germany, Great Britain, Spain, Portugal, Denmark, China and Brazil have achieved as they install and produce ever larger amounts of renewable energy, as well as from the challenges and setbacks that they have encountered along the way. We should learn also from the efforts and successes of the geographically diverse states which are leading the U.S. in wind and solar energy production, including California, Texas and Iowa, which lead the U.S. in wind energy installations, as well as Arizona, North Carolina and New Jersey, which are among the top states for solar power. The key policy learning is the need for stable incentives for demand, production, manufacturing and innovation.

c) NRDC does not oppose nuclear power; however, in NRDC's judgment, nuclear power has longstanding, substantial, unresolved issues regarding safety, non-proliferation, waste and cost. NRDC works as a national environmental advocacy organization to address these nuclear issues. Regarding nuclear energy's role in climate change mitigation, NRDC prioritizes reducing carbon pollution from the existing fleet of fossil-fired power plants by investing in energy efficiency, expanding the use of wind, solar and other sources of renewable power, and shifting generation from high-carbon-emitting existing units towards lower-carbon-emitting ones.

Senator WHITEHOUSE. Thank you very much, Dr. Gowrishankar.

Our next witness is Mr. Darren Smith, who is the Environmental Manager for Devon Energy Corporation, a Fortune 500 company headquartered in Senator Inhofe's home State in Oklahoma City. He served there since January 2009. Devon's oil and natural gas exploration production operations are focused onshore in the United States and Canada, and the company owns natural gas pipelines and treatment facilities in many of its producing areas, making it one of North America's largest processors of natural gas liquids.

Mr. Smith earned his undergraduate degree in biology from the University of Western Ontario and he earned a Master of Science in environmental toxicology from the University of Wyoming-Laramie. We welcome him here today.

Mr. Smith.

STATEMENT OF DARREN SMITH, ENVIRONMENTAL MANAGER, DEVON ENERGY CORPORATION

Mr. SMITH. Thank you, Chairman, for that introduction. Ranking Member Vitter and Ranking Member Inhofe, thank you for the opportunity to testify here today about this very important issue. My name is Darren Smith. I am Devon Energy's environmental policy manager.

Devon Energy Corporation is a leading independent oil and natural gas exploration and production company with operations focused onshore in the U.S. and Canada. We operate in several of the major shale basins in the United States.

Devon has been actively engaged in the last several years in efforts to demonstrate to EPA that its method of estimating methane emissions from oil and gas operations is fundamentally flawed and is resulting in gross overestimates. I testified to that effect last June and extensively described how this faulty data had been contaminating critical public policy research and considerations.

Since that time, Devon has continued to engage EPA in constructive dialog, providing method suggestions and data, some of its from EPA's own greenhouse gas reporting program, to encourage EPA to revise the factor that it uses to estimate methane emissions from hydraulically fractured natural gas wells.

This work is ongoing and Devon remains encouraged that EPA will act swiftly to revise its data. The UT-EDF Fugitive Methane Study that we are discussing today, one that EPA, environmental groups, and industry hold in high regard, confirms what Devon has been telling EPA for the last 2 years, that its estimate for representing methane emissions from hydraulically fractured natural gas wells is an order of magnitude too high. The study confirms that this EPA estimate is in fact 50 times too high.

The time for EPA to finally revise this erroneous emission data is now. There is both consensus and confidence in the data that industry has provided, in the data that has been provided to EPA under its greenhouse gas reporting program, and now in this peer-reviewed scientific study.

Immediate action is vital because EPA estimates have been relied upon by researchers, financial analysts, and various policymakers as a basis for critical public policy considerations. In fact, a recently finalized EPA regulation on the oil and gas industry was justified using this inaccurate data. Equally troubling is a group of Northeastern States that is threatening to sue EPA if it doesn't propose additional emission requirements on the oil and gas sector. All this is driven by the Agency's use of this flawed data. EPA must immediately revise its data to more accurately reflect emissions associated with the source category before further harm is done.

Devon applauds the researchers and the companies that participated in the UT-EDF study for their efforts to shed a necessary scientific light on the topic of fugitive methane emissions from oil and gas operations. It is unfortunate that some of the headlines and discussions surrounding the release of the study suggest that the low emission performance by the oil and gas industry is due solely to recent EPA regulation that forces industry to use emission control equipment. The study fails to recognize that, in fact, the industry had been already voluntarily using many of these controls prior to the EPA mandate, and I should add that the mandate that we are describing had been justified in part using the flawed emission estimate that we are talking about today.

Despite the study's findings that emissions from hydraulically fractured wells are 50 times lower than what EPA previously estimated, the study concludes that, overall, when other methane emission sources are added, methane emissions from gas operations are about the same as EPA previously reported in their inventory.

One source, pneumatic controllers, devices that use gas pressure from the well to maintain fluid levels at a well site when no electricity is available, were found by the study to emit more than EPA's prior estimate, thus offsetting the significant decline in emissions from completions with hydraulic fracturing. The end result is that the overall estimate of methane emissions from the entire system are about 10 percent lower than EPA's.

Many in the industry question whether conclusions about methane emissions from these pneumatic devices are premature since it is known that they will be studied further in phase two of the study, and the researchers have admitted "There was significant geographic variability in the emissions rate from pneumatic controllers between production regions" and, further, that "emissions per controller from the Gulf Coast are highest and are statistically different than emissions from controllers in the Rocky Mountain and Appalachian regions" and, further, "the difference in average values is more than a factor of 10 between Rocky Mountain and Gulf Coast regions."

The bottom line here is that the researchers admittedly cannot explain this variability and have therefore correctly concluded that more study is needed in order to correctly establish what representative emissions are from these devices. We are confident that phase two of the study will ultimately show that a few high emission measurements in one part of the country are not indicative of the nationwide average. In fact, it is likely that phase two will lead to a downward revision of the emission estimates for these devices, from what was found in phase one, as we understand that three out of the four regions already studied have demonstrated low emissions from these devices.

This would mean that the overall methane emissions from gas production would fall even further below the study's current estimate of .42 percent of gross production and remain less than one-third to one-sixth of what critics believe is necessary for natural gas to benefit the climate.

One cannot lose sight of the fact that gas producers are in the business of selling methane and industry will continue to make important innovations to improve efficiency and further reduce emissions. Not only is this a reflection of a strong commitment to environmental stewardship, but it is in the companies' best interest to do so because methane leaks represent lost revenue. I am confident that future studies like the one we are discussing today will continue to reinforce this business fundamental.

With that, this concludes my testimony. Thank you.

[The prepared statement of Mr. Smith follows:]

Testimony of Darren Smith, Environmental Policy Manager, Devon Energy Corporation

Before the Oversight Subcommittee of the Environment and Public Works Committee; Washington, D.C. November 5, 2013.

Chairman Whitehouse, Ranking Member Inhofe, members of the Subcommittee: good afternoon and thank you for the opportunity to testify on such an important issue.

My name is Darren Smith and I am Devon Energy's Environmental Policy Manager.

Devon Energy Corporation is a leading independent oil and natural gas exploration and production company, with operations focused onshore in the United States and Canada, in several of the major U.S. shale basins.

Devon has been actively engaged for the last several years in efforts to demonstrate to EPA that its method of estimating methane emissions from oil and gas operations is fundamentally flawed, resulting in gross overestimates. I testified to that effect in June of last year, and extensively described how this faulty data has been contaminating critical public policy research and considerations.

Since that time, Devon has continued to engage EPA in constructive dialogue, providing methodological suggestions and data – some of it from EPA's own greenhouse gas reporting program – to encourage EPA to revise the factor that it uses to represent methane emissions from hydraulically fractured natural gas wells.

This work is ongoing and Devon remains encouraged that EPA will act swiftly to revise its data. The UT-EDF Fugitive Methane Study that we are discussing today – one that EPA, environmental groups and industry hold in high regard – confirms what Devon has been telling EPA for more than two years: that its emission estimate for hydraulically fractured gas wells is an order of magnitude too high. The Study confirms that this EPA estimate is in fact around ***50 times* too high.**

The time for EPA to *finally* revise this erroneous emissions data is now. There is both consensus and confidence in the data that industry has provided, in the data reported to EPA under its own greenhouse gas reporting rule, and in this new peer- reviewed scientific study.

Immediate action is vital because the EPA estimates have been relied upon by researchers, financial analysts and various policy makers as a basis for critical public policy considerations. In fact, a recently finalized EPA regulation on the oil and gas sector was justified using this inaccurate data. Equally troubling, a group of North Eastern states is threatening to sue EPA if it doesn't propose additional emissions regulations on the sector, in light of the Agency's use of flawed data. EPA must immediately revise its data to more accurately reflect emissions associated with this source category, before further harm is done.

Devon applauds the researchers and companies that participated in the UT-EDF Study, for their efforts to shed a necessary scientific light on the topic of fugitive methane emissions from oil and gas operations. Importantly, while some of the headlines and discussion surrounding the release of this study suggest that the low emission performance by the oil and gas industry is due solely to recent EPA regulations that force industry to use emission control equipment, this is misleading. The Study fails to recognize that in fact the industry was already voluntarily using many of these controls prior to the EPA mandate. I might add, that this mandate was actually justified in part using the flawed emissions estimate that we are discussing today.

Despite the Study's finding that emissions from hydraulically fractured wells are 50 times lower than what EPA previously estimated, the Study concludes that when other methane emission sources are added, methane emissions from overall gas operations are about the same as EPA previously reported in their inventory.

One source, pneumatic controllers – devices that use gas pressure from the well to maintain fluid levels and pressures at a well-site when no electricity is available – were found by the Study to emit more than EPA's prior estimate, thus offsetting the significant decline in emissions from completions with hydraulic fracturing. The end result is that the overall estimates of methane emissions from the entire system are about 10% lower than EPA's.

Many in the industry question whether conclusions about methane emissions from these pneumatic devices are premature since it is known that they will be analyzed further in Phase Two of the Study and the researchers have admitted on page 31 of the appendix: " There was significant geographical variability in the emissions rate from pneumatic controllers between production regions" and further, that: "Emissions per controller from the Gulf Coast are highest and are statistically different than emissions from controllers in the Rocky Mountain and Appalachian regions," and further "The difference in average values is more than a factor of 10 between Rocky Mountain and Gulf Coast regions."

The bottom line is that the researchers admittedly cannot explain this variability and have therefore correctly concluded that more study is needed in order to correctly establish what representative emissions are from these devices. We're confident that Phase Two of the Study will ultimately show that a few high emission measurements in one part of the country are not indicative of the nation-wide average. In fact, it's likely that Phase Two will lead to a downward revision of the emissions estimates from Phase One, as we understand that three out of the four regions already studied have demonstrated low emissions from these devices.

This would then mean that the overall methane emissions from gas production would fall **even further below the Study's current estimate of 0.42 % of gross production and remain less than one-third to one-sixth of what critics believe is necessary for natural gas to benefit the climate.**

One cannot lose sight of the fact that natural gas producers are in the business of selling methane and the industry will continue to make important innovations to improve efficiency and further reduce emissions. Not only is this a reflection of a strong commitment to environmental stewardship, but it is in companies' best interest to do so, because methane leaks represent lost revenue. I'm confident that future studies like the one we're discussing today will continue to reinforce this business fundamental.

This concludes my testimony. Thank you.

Questions from Senator Barbara Boxer:

1. **EPA's new Source Performance Standards for Oil and Gas Production do not currently contain requirements to control the emissions from many types of emissions control equipment used at oil and gas wells. Would the establishment of standards for pneumatic devices at wells, pressure relief valves at storage tanks, and the compressors and pressurized motors used to move natural gas through processing plants and pipelines reduce VOC, methane and other emissions?**

Reponse: Each of the devices listed in the above question are in fact already regulated under EPA's NSPS OOOO, which was first finalized in August 2012. As such, standards have already been set by EPA for pneumatic devices at well sites, storage tanks, and both reciprocating and centrifugal compressors at gas processing facilities. I have copied the specific reference for each, under NSPS OOOO below.

Pneumatic Control devices at wells are regulated under 40 CFR § 60.5390 as follows:

§60.5390 What standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the VOC standards, based on natural gas as a surrogate for VOC, in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from this requirement.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety and positive actuation. However, you must tag such pneumatic controller with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller, as required in §60.5420(c)(4)(ii).

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in §60.5420(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013, at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must have a bleed rate less than or equal to 6 standard cubic feet per hour.

Storage Tank Emissions are in fact specifically covered under 40 CFR § 60.5395. These regulations would apply to any emissions from the storage tank, and not just from pressure relief valves. They are regulated as follows:

§60.5395 What standards apply to storage vessel affected facilities?

Except as provided in paragraph (h) of this section, you must comply with the standards in this section for each storage vessel affected facility.

(a)(1) If you are the owner or operator of a Group 1 storage vessel affected facility, you must comply with paragraph (b) of this section.

(2) If you are the owner or operator of a Group 2 storage vessel affected facility, you must comply with paragraph (c) of this section.

(b) Requirements for Group 1 storage vessel affected facilities. If you are the owner or operator of a Group 1 storage vessel affected facility, you must comply with paragraphs (b)(1) and (2) of this section.

(1) You must submit a notification identifying each Group 1 storage vessel affected facility, including its location, with your initial annual report as specified in §60.5420(b)(6)(iv).

(2) You must comply with paragraphs (d) through (g) of this section.

(c) Requirements for Group 2 storage vessel affected facilities. If you are the owner or operator of a Group 2 storage vessel affected facility, you must comply with paragraphs (d) through (g) of this section.

(d) You must comply with the control requirements of paragraph (d)(1) of this section unless you meet the conditions specified in paragraph (d)(2) of this section.

(1) Reduce VOC emissions by 95.0 percent according to the schedule specified in (d)(1)(i) and (ii) of this section.

(i) For each Group 2 storage vessel affected facility, you must achieve the required emissions reductions by April 15, 2014, or within 60 days after startup, whichever is later.

(ii) For each Group 1 storage vessel affected facility, you must achieve the required emissions reductions by April 15, 2015.

(2) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology. Monthly calculations must be based on the average throughput for the month. Monthly calculations must be separated by at least 14 days. You must comply with paragraph (d)(1) of this section if your storage vessel affected facility meets the conditions specified in paragraphs (d)(2)(i) or (ii) of this section.

(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (d)(1) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.

(ii) If the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (d)(1) of this section within 30 days of the monthly calculation.

(e) Control requirements. (1) Except as required in paragraph (e)(2) of this section, if you use a control device to reduce emissions from your storage vessel affected facility, you must equip the storage vessel with a cover that meets the requirements of §60.5411(b) and is connected through a closed vent system that meets the requirements of §60.5411(c), and you must route emissions to a control device that meets the conditions specified in §60.5412(c) and (d). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of §60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(f) Requirements for storage vessel affected facilities that are removed from service. If you are the owner or operator of a storage vessel affected facility that is removed from service, you must comply with paragraphs (f)(1) and (2) of this section.

(1) You must submit a notification in your next annual report, identifying all storage vessel affected facilities removed from service during the reporting period.

(2) If the storage vessel affected facility identified in paragraph (f)(1) of this section is returned to service, you must comply with paragraphs (f)(2)(i) through (iii) of this section.

(i) If returning your storage vessel affected facility to service is associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (d) of this section immediately upon returning the storage vessel to service.

(ii) If returning your storage vessel affected facility to service is not associated with a well that was fractured or refractured, you must comply with paragraphs (f)(2)(ii)(A) and (B) of this section.

(A) You must determine emissions as specified in §60.5365(e) within 30 days of returning your storage vessel affected facility to service.

(B) If the uncontrolled VOC emissions without considering control from your storage vessel affected facility are 4 tpy or greater, you must comply with paragraph (d) of this section within 60 days of returning to service.

(iii) You must submit a notification in your next annual report identifying each storage vessel affected facility that has been returned to service.

(g) Compliance, notification, recordkeeping, and reporting. You must comply with paragraphs (g)(1) through (3) of this section.

(1) You must demonstrate initial compliance with standards as required by §60.5410(h) and (i).

(2) You must demonstrate continuous compliance with standards as required by §60.5415(e)(3).

(3) You must perform the required notification, recordkeeping and reporting as required by §60.5420.

(h) Exemptions. This subpart does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, 40 CFR part 63, subparts G, CC, HH, or WW.

Also, Compressors at processing plants are in fact covered under 40 CFR § 60.5380 and 40 CFR § 60.5285. I am interpreting the term "pressurized motors" to refer to the engines that drive the compressors in question, which would be covered under these regulations and also NESHAP ZZZZ, NSPS JJJJ, and NSPS IIII as well:

§60.5380 What standards apply to centrifugal compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section for each centrifugal compressor affected facility.

(a)(1) You must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411(b), that is connected through a closed vent system that meets the requirements of §60.5411(a) and routed to a control device that meets the conditions specified in §60.5412(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by §60.5410(b).

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by §60.5415(b).
(d) You must perform the required notification, recordkeeping, and reporting as required by §60.5420.

§60.5385 What standards apply to reciprocating compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.
(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section.
(1) Before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.
(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.
(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by §60.5410.
(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by §60.5415.
(d) You must perform the required notification, recordkeeping, and reporting as required by §60.5420.

Each of the devices listed in the question are currently regulated under EPA's New Source Performance Standards for Oil and Gas Production. Establishing further requirements, before allowing the new requirements to decrease emission rates across the industry, would have very little effect on actual emissions.

2. **EPA's new Source Performance Standards for Oil and Gas Production do not contain requirements to control the completion and production emissions from wells that co-produce oil and natural gas. Do such co-produced wells release VOCs, methane and other emissions that can be controlled through reduced emission completions and other readily available technologies?**

Response: Wells that are classified with state agencies as oil wells often also produce some amount of natural gas, alongside the oil. Oil produced from these wells is a mixture of hydrocarbon chains of differing lengths, some of which are in the gas phase while at surface temperature and pressure. However, these wells do not typically produce a large amount of gas, as compared to natural gas wells, which produce almost exclusively gas, and very little if any liquid hydrocarbons.

, Oil and gas operators use control devices such as flares, combustors, or other equipment to limit emissions of VOCs and methane to comply with state regulations that ensure that any emissions including VOCs and methane are either below the limit for the regulation in the jurisdiction.. Reduced emission completion (REC) equipment can only be used on wells that will flow on their own and with sufficient pressure after hydraulic fracturing. It is gas that allows a well to flow and it is therefore impractical or impossible to use RECs on oil wells with insufficient gas flow. REC equipment not only requires certain flow characteristics at the wellhead, it also requires that a gas collection line be available at the site that is sized appropriately to handle the volume of gas produced.

Questions from Senator David Vitter:

1. **What is the main difference between EPA's previous estimates of methane emissions from hydraulic fracturing and the actual emissions measured by the UT-EDF study? Can you explain why those numbers are so different and why EPA's figured were so overestimated?**

__Response:__ The main difference between EPA's previous estimates of emissions from hydraulic fracturing completions and actual emissions found in the UT-EDF study is the amount of time flowback occurs. EPA based its original methodology on Natural Gas Star data, which was data reported for natural gas captured by Reduced Emission Completion (REC) equipment. This equipment changes the cost dynamic of a gas well in a very dramatic way.

Flowback involves the removal of impurities, chemicals, water, and sand from a gas well by allowing the downhole pressure to push water and debris back up the well so it can be safely disposed of. The period during which flowback occurs is typically right after the final stage of hydraulic fracturing occurs, and varies in length. The purpose of flowback is to allow the equipment that handles the produced liquids to safely operate without risk of corrosion or plugging from the sand and other impurities that would be produced were flowback not to occur.

In a completion where REC equipment is not used, completion, gas that is produced during flowback must be either vented or flared, as there is no equipment available to route it to a sales line. Operators want to minimize the volume of this gas flared as much as possible, to avoid destroying valuable product. Typically, once gas has been flowing consistently for a couple of hours, operators shut the well in, attach the wellhead to a permanent sales line, and begin routing the gas produced to sales. This minimizes the value lost during the completion process. For this reason, these flowbacks typically last only a few days, and are often only producing measurable quantities of gas during the last several hours of operation.

When REC equipment is used, operators do not have the same concern over lost product, as all gas that is produced is routed effectively to a sales line, while impurities, sand, and water are removed from the stream simultaneously to be effectively disposed of. For this reason, REC equipment can be used for a very long period of time, often upwards of 10 to 12 days, capturing all of the gas that is produced during that time period. Given that a well typically increases production from the time that flowback starts to when flowback ends, this captured volume over 10 to 12 days is often orders of magnitude higher than volume of gas that would be released in a typical 3 to 4 day completion without REC equipment.

EPA's error, reflected by the dramatically different results identified in the UT-EDF study, is that the Agency assumed that all gas that was captured by REC equipment would have otherwise been released into the atmosphere. As shown by the UT-EDF study and through data provided to EPA through Devon's URS study, this is simply not the case.

2. **Although the UT-EDF study initially found greater than expected fugitive methane emissions from pneumatic controllers, you pointed out in your testimony that there was "significant geographical variability in the emissions rate from pneumatic controllers between production regions." In your mind, is this further justification for why hydraulic fracturing is better regulated at the state level to deal with the vast "geographical variability?" Can you please elaborate on the issue of emissions from pneumatic controllers.**

Response: The UT-EDF study highlighted in its findings something that operators are already well aware: emission rates will vary widely from site to site based on production type, production volumes, down-hole and surface temperature and pressure, and local geography. In fact, the study was unable to determine the cause of the variability found in their particular results, and suggested that further study of pneumatic controllers would be required. The study itself mentions that:

> *"There is significant geographical variability in the emissions rate from pneumatic controllers between production regions. Emissions per controller from the Gulf Coast are highest and are statistically different than emissions from controllers in Rocky Mountain and Appalachian regions. The Rocky Mountains have the lowest emissions. The difference in average values is more than a factor of ten between Rocky Mountain and Gulf Coast regions."*

Devon's operations were not measured in the study itself, and to comment on individual sites would take knowledge of the operating equipment at those sites and the characteristics of the produced fluids. However, the important data from this portion of the study is the finding that different regions have dramatically different emission rates from pneumatic controllers.

Pneumatic controllers are small devices that vent a small amount of pressurized gas to drive valves to control flow from separators, tanks, and other equipment on site. These devices allow site automation without the use of electricity or the constant operation of engines to run the devices. Significant progress has been made in recent years in the design of this equipment to both reduce the amount of vented gasses (these devices are called "low bleed controllers") and to design equipment that only vents when the device is actuated (these are called "intermittent bleed controllers"). These new designs, when operating parameters allow their use, have been installed by operators over the past decade to capture vented methane that would have previously been lost.

Equipment actuation drives the emission rate for pneumatic controllers. Separators at sites producing high volumes of liquid are required to frequently dump their product into tanks – sometimes several times an hour – but separators at sites that are not producing high volumes of liquid do not actuate as often. So for fields that are dominated by wells that have been producing for years and are now in the last portion of their operating lifetime, pneumatic controller emissions may be lower than newly developing fields. Also, fields that are producing more liquids might have higher pneumatic controller emissions as well, but it will also depend on the amount of gas produced in those fields.

This is just an example among many that different fields require different approaches and technology to tackle different environmental challenges. For this reason, a simple one-size-fits-all approach is inadequate to protect the local environments within different regions of states. The states are best equipped with the both expertise and local accountability necessary for the responsible stewardship of our land, water, and air. For this reason, and because Devon values environmental stewardship, Devon supports regulation of all oil and gas activities by the states, rather than the federal government.

Questions from Senator James Inhofe:

1. **How has the natural gas industry recognized that fugitive methane emissions exist and taken steps to ameliorate the impact?**
2. **What Incentive does the natural gas industry have to reduce fugitive methane emissions?**

Response: *[Note: I have answered these two questions in a single response, as their answers are interrelated.]* Devon Energy, along with many other responsible operators, have taken various steps to minimize methane emissions wherever possible. Devon, for example, completed a program to replace all continuous bleed pneumatic devices with low emitting devices at field sites in South Central Wyoming This significantly reduced methane lost during normal operations.

Operators also flare fugitive methane as standard industry practice wherever possible during completion events. This flaring not only eliminates any explosion risk for our on-site workers, but it also reduces the heat trapping potential of the released gas by a significant factor. The reasoning behind this is two-fold. First, state regulations require operators to reduce emissions from field sites in a variety of ways, often using new and innovative technologies.

Second, and more importantly, operators have a financial obligation to their shareholders to waste as little methane as possible during operations. Methane is a primary product of our industry. To the public, it is an important product that is used to heat homes, generate electricity, drive vehicles, and create products that we use every day. But to operators, it is the valuable result of millions of dollars in investment and decades of technology development. For Devon to let much of this methane escape into the atmosphere, or to burn it off any more of it than absolutely necessary not only does a disservice to Devon's shareholders and the public, but also would make Devon less competitive with other operators who were more prudent.

3. **Does the natural gas industry need regulations to reduce fugitive methane emissions?**

Response: As discussed above, it is in the best interest of the natural gas industry to capture and collect as much methane as possible, and for that reason, operators do so wherever economically and technically feasible. While Devon supports responsible and cost-effective regulation at the state level to ensure that operators follow responsible practices from an environmental standpoint, operators are financially motivated to control methane emissions as much as possible. For this reason, no, the natural gas industry does not need additional regulations to reduce fugitive methane emissions.

Senator WHITEHOUSE. Thank you, Mr. Smith. I appreciate it.

Our final witness is A. Daniel Hill, who is the department head and holder of the Noble Chair in petroleum engineering at Texas A&M University. Professor Hill also holds the Robert Whiting Endowed Chair. Prior to joining the faculty of Texas A&M, Dr. Hill taught for 22 years at the University of Texas at Austin, and before that, before entering academia, he spent 5 years as an advanced research engineer with Marathon Oil Company. He serves on the Society of Petroleum Engineers Editorial Review Committee and chairs the Society of Petroleum Engineers Hydraulic Fracturing Technology Conference.

He holds three degrees in chemical engineering, a bachelor of science from Texas A&M, a masters and doctorate from the University of Texas at Austin, and we are delighted to have him here today.

Professor Hill.

STATEMENT OF A. DANIEL HILL, Ph.D., P.E., DEPARTMENT HEAD, PETROLEUM ENGINEERING, TEXAS A&M UNIVERSITY

Mr. HILL. Thank you, Chairman Whitehouse and Ranking Member Inhofe and Senator Vitter. Good afternoon. I am Dan Hill. I am the head of the Harold Vance Petroleum Engineering Department at Texas A&M University. I have been a faculty member for over 30 years, after working in industry for about 5 years.

In recent years, one focus of my research has been various aspects of hydraulic fracturing of shale gas and oil reservoirs. Hydraulic fracturing, of course, is the key well completion technique that has enabled the production of huge quantities of natural gas and oil from shale reservoirs to the enormous benefit to the U.S. economy and to U.S. consumers.

In February 2012, I was invited by Professor David Allen of the University of Texas to serve on the scientific advisory panel for the planned comprehensive study of methane emissions at natural gas production sites in the United States. As a member of the advisory panel for this methane emission study, I reviewed the planned measurement program, reviewed results partway through the study, reviewed the final results, and reviewed the publications describing the outcomes. Throughout the study, I was impressed with the careful and thorough approach of the study team. I would say that this was the unanimous opinion of the scientific advisory panel.

Unconventional oil and gas production has changed the U.S. energy game. Production of natural gas and oil from unconventional reservoirs, primarily shale formations, is soaring, daily lessening this country's dependence on imported oil and natural gas. A slide that you Senators have is a history and forecast of U.S. natural gas supply. In less than 10 years gas production from shale formations has grown to over 30 percent of the U.S. supply and continues to grow. In fact, in a recent update to this 2011 forecast, the EIA is now predicting that the United States will be a net gas exporter before the year 2020. This is great news in every possible way: natural gas is the cleanest burning fossil fuel, it yields the least CO_2, and it is low cost thanks to its newfound abundance in unconventional reservoirs.

Thus, it is critical that development of natural gas production from shales continues in an environmentally responsible fashion. In my opinion, this study has alleviated the fear that large volumes of natural gas are emitted during the flowback period following hydraulic fracturing. However, the study did reveal significant sources of natural gas emissions occurring during other shale gas well operations.

The measurement protocols used were sound and were properly applied. The validity of this study is founded on the measurement methods used and their correct application. The methods chosen were all proven from years of prior practice and were properly calibrated and applied in this study.

The study is comprehensive. In this study, methane emissions were measured at 190 well sites, with 489 hydraulically fractured gas wells at these sites. The well sites were located in the Gulf Coast, the Mid-Continent, Rocky Mountain, and the Appalachian regions of the U.S. Slide 4 shows the regions studied. The measures were made on sufficient numbers of well sites to make the results statistically valid and extrapolatable.

Methane emissions during hydraulic fracturing flowback operations are 36 times less than that estimated in the EPA's 2011 greenhouse gas inventory. The most important finding of this study is that methane emissions during the flowback period immediately following hydraulic fracturing are dramatically less than that estimated by the EPA in its 2011 greenhouse gas inventory, more than 36 times less. The EPA estimate was not based on actual measured methane emissions, as this study is, but simply assumed a certain percentage of all methane produced during flowback was emitted. Obviously, the assumed percentage emitted was too high, 36 times too high.

Significant volumes of methane are being emitted from pneumatic controllers, from pumps, and from leaks. The study found that emissions from these devices exceed the 2011 EPA estimates and are by far the largest sources of methane emissions at shale gas well sites. Many of these emission sources are easily reducible.

More study of methane emissions during gas well unloading is needed. In this study, only nine gas well unloading events were monitored for methane emission, and in only three of these, all located in the Gulf Coast region, significant methane emissions occurred. The range of emissions measured during these few tests were extremely variable and not easily generalizable. I recommend that a comprehensive study of methane emissions during unloading be conducted, following protocols like those used in this study, and apparently some are already underway.

Fugitive methane emissions are only .42 percent of the produced gas from shale wells. This study has shown that amount is produced from shale well sites and emitted to the atmosphere. It also showed that the large majority of emissions occurred during normal production and is not related to flowback after hydraulic fracturing. It is instructive to realize that .42 percent of current U.S. shale gas production is about 42 billion cubic feet per year, which even at current low prices has a value of about $150 million. This is a significant economic target for the industry to capture by applying improved practices and developing new technologies.

Thank you.

[The prepared statement of Mr. Hill follows:]

Written Testimony

Committee on Environment and Public Works

U. S. Senate

November 5, 2013

Good Morning. I am Dan Hill and I am the Head of the Petroleum Engineering Department at Texas A&M University. I have been a faculty member for over 30 years after working in industry for about 5 years, and throughout my career I have conducted research on methods to improve oil and gas production. In recent years, one focus of my research has been various aspects of hydraulic fracturing of shale gas and oil reservoirs. Hydraulic fracturing is the key enabling well completion technique that has enabled the production of huge quantities of natural gas and oil from shale reservoirs to the enormous benefit to the U.S. economy and to U.S. consumers. In February, 2012, I was invited by Professor David Allen of the University of Texas at Austin to serve on the scientific advisory panel for the planned comprehensive study of methane emissions at natural gas production sites in the United States. I was happy to accept this invitation because this study was to be the first to my knowledge that would actually measure fugitive methane emissions from shale gas wells at many sites around the United States. Prior to this study, there was speculation in some publications that very large volumes of natural gas were being emitted during the flow back period immediately after hydraulic fracturing operations were completed. The assumptions made to derive such estimates did not seem reasonable, so I was anxious to see the results of actual emissions measurements made carefully and scientifically.

As a member of the Scientific Advisory Panel for this methane emissions study, I reviewed the planned measurement program, reviewed results part way through the study, reviewed the final results, and reviewed the publications describing the study and its results. Throughout the study, I was impressed with the careful and thorough approach of the study team. I would say that this was the unanimous opinion of the Scientific Advisory Panel.

Unconventional oil and gas production has changed the U. S. energy game.

In just a few years, applications of advanced technology have led to the most dramatic economic boost our country has seen in my lifetime. Production of natural gas and oil from unconventional reservoirs, primarily shale formations, is soaring, daily lessening this country's dependence on imported oil and natural gas. Slide 1 is a history and forecast of the U. S. natural gas supply – in less than 10 years, gas production from shale formations has grown to over 30% of the U. S. supply, and continues to grow. In fact, in a recent update to this 2011 forecast, the EIA is now predicting that the United States will be a net gas exporter before 2020.This is great news in every possible way – natural gas is the cleanest burning fossil fuel, it yields the least CO_2, and it is low cost, thanks to its newfound abundance in unconventional reservoirs.

The dramatic growth in U.S. natural gas production has come almost entirely from shale formations. As illustrated in Slide 2, there are large volumes of natural gas being produced from many different shale formations and the production from these reservoirs continues to increase despite the current low gas prices.

Thus, it is critical that development of natural gas production from shales continues in an environmentally responsible fashion. In my opinion, this study has alleviated the fear that large volumes of natural gas are emitted during the flowback period following hydraulic fracturing. However, this study did reveal significant sources of natural gas emissions occurring during other shale gas well operations. I feel confident that these important findings will cause operators to take measures to significantly reduce theses emissions.

Measurement protocols were sound and properly applied.

The validity of this study is founded on the measurement methods used and their correct application. The methods chosen were all proven from years of prior practice and were properly calibrated and applied in this study. To measure methane emissions during flowback or well unloading operations, gas from all possible vents from the tanks or separators receiving gas and liquids from the well was captured and forced through devices that measured the gas flow rate. The gas was sampled to measure the methane concentration. Slide 3 is a photograph of such a setup at one of the studied well sites and a schematic of the measurement apparatus.

Emissions from pneumatic controllers, pumps, and other leaking equipment were measured by first locating the leaks with an infrared camera, then measuring the emission rate with a device that essentially vacuums the leaking gas into itself, where flow rate and methane concentration are measured. This device has been in use for measuring leaks for decades.

Finally, on a few well sites, methane concentration was measured downwind of the well site to insure that no significant source of methane emissions had been missed. In all cases, this downwind measurement corroborated the point source measurements, confirming that no undetected major leaks or other emissions were occurring.

The study is comprehensive.

In this study, methane emissions were measured at 190 well sites, with 489 hydraulically fractured gas wells at these sites. The well sites were located in the Gulf Coast, Mid-Continent, Rocky Mountain, and Appalachian regions of the U.S. (Slide 4). Measurements were made on sufficient numbers of well sites to make the results statistically valid. Thus, within a reasonable statistical tolerance, the results of this study can be generalized to the more than 440,000 onshore gas wells in the United States.

Methane emissions during hydraulic fracturing flowback operations are 36 times less than that estimated in the EPA's 2011 greenhouse gas inventory.

The most important finding of this study is that methane emissions during the flowback period immediately following hydraulic fracturing are dramatically less than that estimated by the EPA in its 2011 greenhouse gas inventory – more than 36 times less. The EPA estimate was not based on actual measured methane emissions, as this study is, but simply assumed a certain percentage of all methane produced during flowback was emitted. Obviously, the assumed percentage emitted was too high, 36 times too high. Common industry practice during flowback operations is to separate the produced gas from the produced liquids, with the gas either being flared (the methane burned) or sent to a sales line. So, it is not surprising that emissions measured in this study during flowback operations were low.

Significant volumes of methane are being emitted from pneumatic controllers, from pumps, and from leaks.

This study found that emissions from pneumatic controllers, chemical pumps, and leaks exceed the 2011EPA estimates and are by far the largest sources of methane emissions at shale gas well sites. These emission sources are easily reducible. For example, pneumatic controllers, the largest source of methane emissions have high bleed and low bleed types, with the emissions being much larger from the high bleed type. It has been demonstrated that most high bleed controllers can be economically replaced with low bleed controllers.

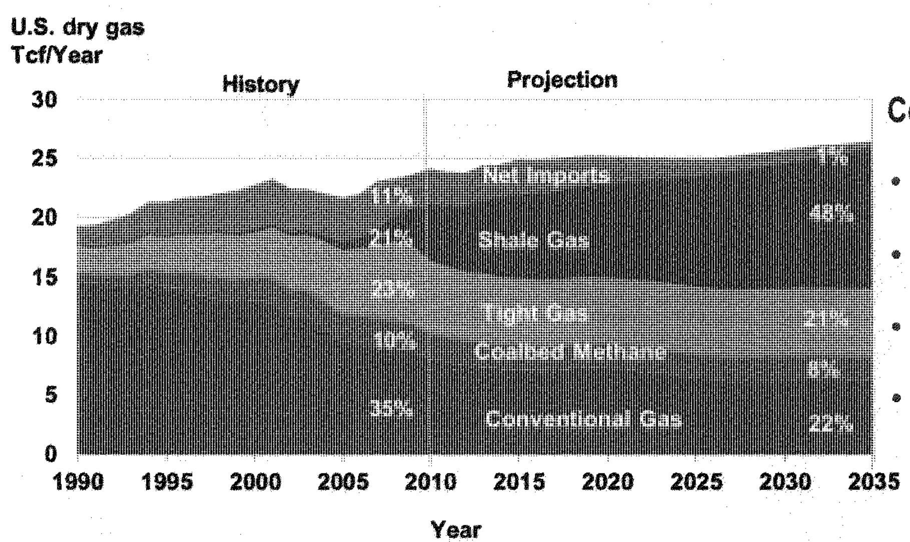
More study of methane emissions during gas well unloading is needed.

In this study, only nine gas well unloading events were monitored for methane emission, and in only three of these, all located in the Gulf Coast region, significant methane emissions occurred. The range of emissions measured during thes few tests was extremely variable, and not easily generalized. Unloading of gas wells by lowering the wellhead pressure is a common practice with shale gas wells, so it is important to understand the level of emissions from these operations. I recommend that a comprehensive study of methane emissions during unloading be conducted, following protocols like those used in this study.

Fugitive methane emissions are only 0.42% of the produced gas from shale wells.

This study has shown that only 0.42% of the methane produced from shale gas well sites is emitted as fugitive gas. It also showed that the large majority of emissions occur during normal production, and are not related to flow back after hydraulic fracturing. It is likely that this study will lead to improved industry practices that will significantly reduce methane emissions from shale gas well sites. It is instructive to realize that 0.42% of the current U. S. shale gas production is about 42 Bcf/year of gas, which even at current low prices, has a value of about $150 million. This is a significant economic target for the industry to capture by applying improved practices and developing new technologies.

UG Plays A Major Role In Future

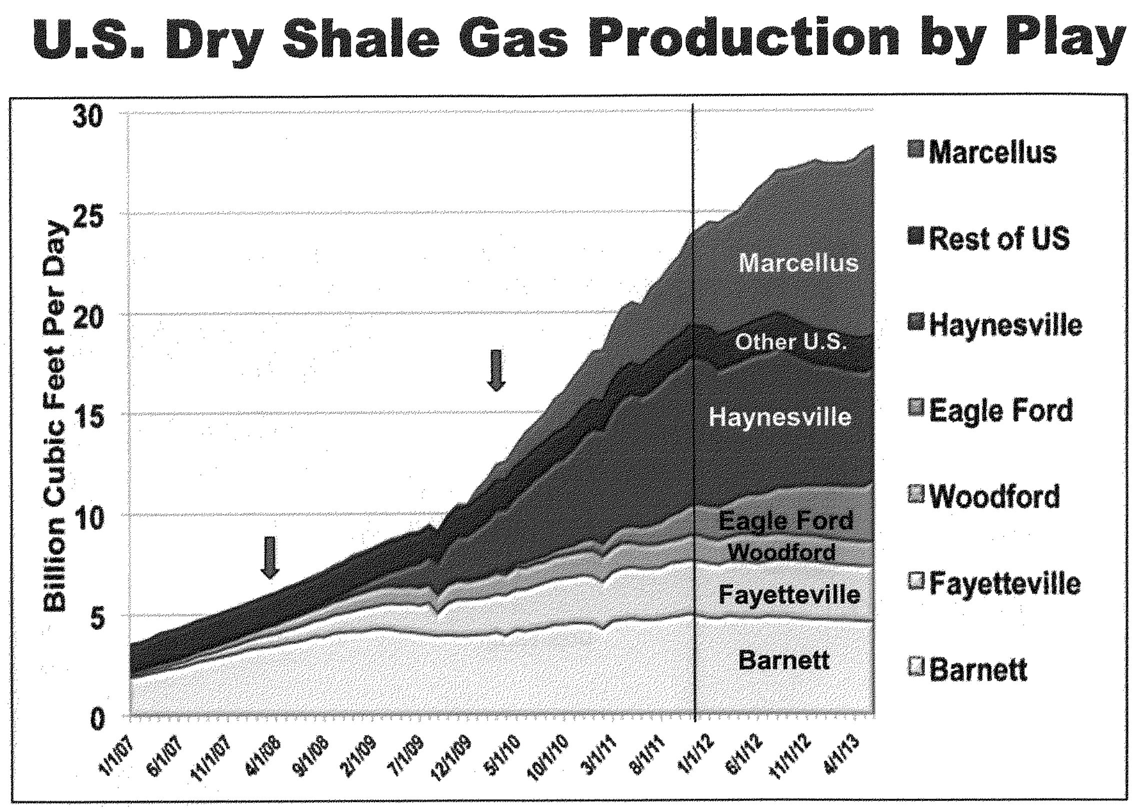


Consumption:

- 24.2 Tcf/year
- UG: 13.0 Tcf/year.
- Conventional: 8.6 Tcf
- Net imports: 2.6 Tcf

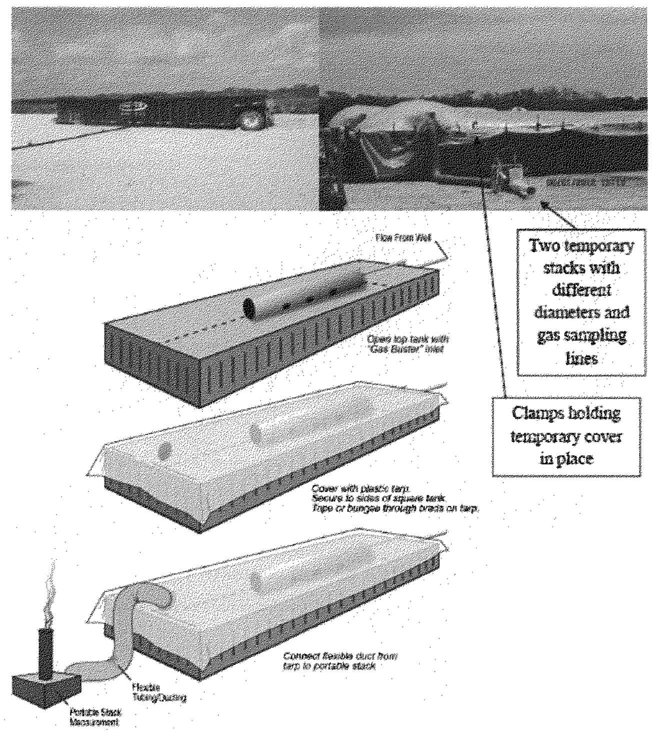
❑ Natural gas production has increased over the last few years, largely due to increased unconventional gas production.

Source: EIA, *Annual Energy Outlook 2012*

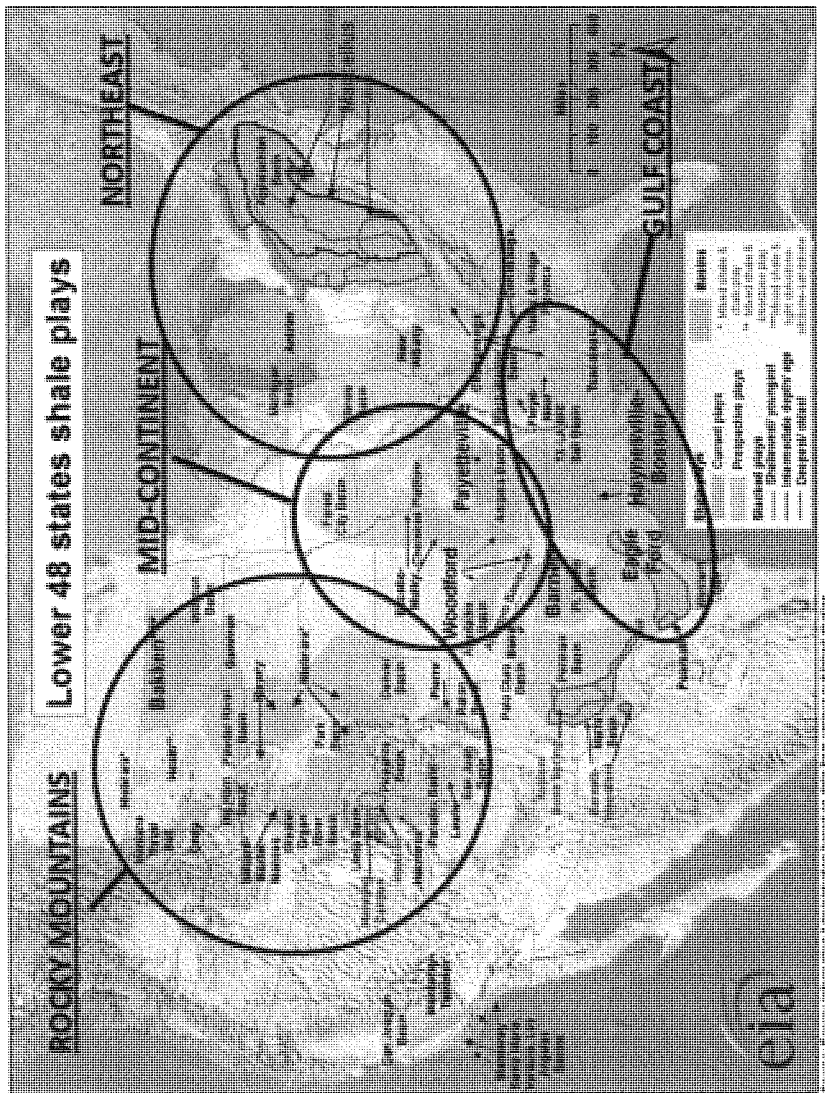


Data from *EIA 2013*

Open Top Tank Used in Flowback



Allen, et al., *PNAS*, 2013


Lower 48 states shale plays
ROCKY MOUNTAINS
MID-CONTINENT
NORTHEAST
GULF COAST
Bakken
Woodford
Fayetteville
Barnett
Eagle Ford
Haynesville-Bossier
eia

Harold Vance Department of
PETROLEUM ENGINEERING
TEXAS A&M UNIVERSITY

A. Daniel Hill
Noble Endowed Chair
Department Head
(979) 845-2244
danhill@tamu.edu

January 3, 2014

Mara Stark-Alcala
Senate Committee on Environmental and Public Works
410 Dirksen Senate Office Building
Washington, DC 20510

Dear Ms. Stark-Alcala:

My answers to the questions from Senators Boxer and Vitter are given below after their questions.

Senator Boxer's questions:

1. **Several other peer reviewed studies have analyzed the methane emission rates associated with oil and gas drilling and found the emission rates to be significantly higher than emission rates derived from the data collected in the University of Texas study entitled "Measurements of methane emissions at natural gas production sites in the United States," Proceedings of the National Academy of Sciences (October 29, 2013) ("UT Study"). Does the UT Study invalidate the findings of the following two peer reviewed studies? If your answer is in the affirmative, please provide the published peer review literature other than the UT Study that supports such a conclusion.**

   - **Anna Karion, et al (2013) "Methane emissions estimate from airborne measurements over a western United States natural gas field," Geophysical Research Letters Volume 40, Issue 16, pages 4393-4397.**

   - **J. Peischl, et al, (2013) "Quantifying sources of methane using light alkanes in the Los Angeles basin, California," Journal of Geophysical Research: Atmospheres, Volume 118, Issue 10, pages 4974-4990.**

I cannot conclude that the UT Study invalidates the findings of the Karion et al. (2013) or the Peischl et al. (2013) studies because the UT Study did not make any measurements in the same geographic areas as these studies; however, the UT Study seriously questions the validity of the methodologies applied in these previous studies. In the UT Study, all of the methane emitted during various gas well operations was captured and the quantity of methane emitted accurately measured. For the almost 200 well sites measured in the UT Study, the amount of methane actually emitted is irrefutable, because it was captured and directly measured.

On the other hand, in the Karion et al. and Peischl et al. studies, a minute fraction of the atmosphere downstream from possible methane emission sites was sampled, and the amount of methane emitted from oil and gas wells estimated by extrapolating these measurements over huge volumes of the atmosphere relative to the sample size, and then subtracting uncertain estimates of the amount of methane emitted from other sources. There are two sources of potentially very large errors in such an approach. First, to estimate methane emissions from a large area based on downstream airborne measurements requires making numerous assumptions such as constant wind speed and uniform wind velocity over thousands of vertical feet of atmospheric space, and thus is always uncertain. A second large source of error in the Karion et al. (2013) or the Peischl et al. (2013) studies is the fact that the inferred methane emissions from oil and gas production operations was obtained by subtracting estimated emissions from other methane sources (cars, cows, etc.) from the estimated total emissions from the aerial surveys. As any scientist knows, when taking the difference between uncertain quantities, the uncertainty of the result is always higher.

Mailing Address:
3116 TAMU
College Station, TX 77843-3116
Web - http://www.pe.tamu.edu

Department Head Office:
507 Richardson Building
College Station, TX 77843-3116
Tel. 979.845.2244 Fax 979.862.6579

If a study were conducted using the UT Study protocol at the sites studies by Karion et al. (2013) and Peischl et al. (2013), their results would almost certainly be invalidated. It is simply not reasonable to expect that methane emissions in the regions studied by Karion et al. (2013) and Peischl et al. (2013) are on the order of 10% of total production as they found, while in 4 other major oil and gas producing regions in the country, the average methane emissions are on average 0.42% of total production, as found in the UT Study.

2. **EPA's New Source Performance Standards for Oil and Gas Production do not currently contain requirements to control the emissions from many types of emissions control equipment used at oil and gas wells. Would the establishment of standards for pneumatic devices at wells, pressure relief valves at storage tanks, and the compressors and pressurized motors used to move natural gas through processing plants and pipelines reduce VOC, methane and other emissions?**

First, I will presume that in the first sentence of this question that Senator Boxer meant to say "control equipment", not "emissions control equipment", because the devices described in the second sentence are process control equipment, not emissions control equipment. The establishment of standards for pneumatic control devices could potentially reduce methane emissions. For example, EPA studies in collaboration with industry have shown the economic benefit of replacing higher emitting pneumatic controllers with lower emitting devices. Any possible standards for pressure relief valves should be very carefully considered and are likely unnecessary because of the very infrequent emissions from such devices. Pressure relief valves on storage tanks or other equiment are safety devices designed to release gas only if the pressure in the vessel reaches an unsafe level, and such events are rare. I do not know what standards could be applied to compressors and pressurized motors, with a reasonable chance of beneficial impact, and with a reasonable chance of enforcement, as such devices do not emit VOC or methane during normal operations.

3. **EPA's New Source Performance Standards for Oil and Gas Production do not contain requirements to control the completion and production emissions from wells that co-produce oil and natural gas. Do such co-produced wells release VOCs, methane and other emissions that can be controlled through reduced emission completions and other readily available technologies?**

Wells that co-produce oil and gas can possibly release VOC, methane, or other emissions, just as natural gas wells can. Similar emission control devices and methodologies are applied to wells producing oil and gas as are to natural gas wells.

Senator Vitter's questions:

1. **Dr. Hill, your work on this study is very much appreciated and I must say I was very pleased to see that not only you, but the Environmental Defense Fund strongly defends the scientific integrity and rigor used in the creation of this report. Could you please elaborate on your role on the scientific advisory panel and the scientific reliability of the report? Is this typical of the rigor used in other studies like the Cornell Howarth and Ingraffea study?**

The role of the scientific advisory panel in the UT Study was to review the measurement practices and the resulting data analyses to insure that the best scientifically reliable results of actual methane emissions from natural gas well sites were obtained. We reviewed the planned measurement program, and were unanimously satisfied that the approach was sound. The panel carefully reviewed the findings of the study, with particular attention being paid to the statistical validity of the results. We also carefully reviewed any extrapolations made to insure that no unfounded claims were being made.

The Cornell Howarth and Ingraffea study, on the other hand, applied no such scientific rigor, and has been widely discredited, including by colleagues at Cornell. The Howarth and Ingraffea study did not use any actual measurements of methane emissions from well sites, as did the UT Study. Instead, their study simply assumed the amount of methane emissions that would occur during particular well operations. The assumptions made of the level of emissions during flowback operations after hydraulic fracturing were particularly unrealistic and have been invalidated by the UT Study. The UT Study shows that the emissions levels during flowback assumed by Howarth and Ingraffea were orders of magnitude too high.

Mailing Address:
3116 TAMU
College Station, TX 77843-3116
Web - http://www.pe.tamu.edu

Department Head Office:
507 Richardson Building
College Station, TX 77843-3116
Tel. 979.845.2244 Fax 979.862.6579

2. **Studies have shown benefits from natural gas when the methane leakage rate as a fraction of the total production of natural gas is below 3 percent. The UT-EDF study shows that only 0.42 percent of methane produced from shale gas well sites is emitted as fugitive gas. In your opinion is there much disputing the importance of natural gas production and its benefits?**

   There are no rational arguments against the importance of increased U.S. natural gas production and its benefits to this country. I will repeat what I testified before the U. S. House of Representatives Committee on Science, Space, and Technology in 2012: 'In just a few years, applications of advanced technology have led to the most dramatic economic boost our country has seen in my lifetime. Production of natural gas and oil from unconventional reservoirs, primarily shale formations, is soaring, daily lessening this country's dependence on imported oil. In less than 10 years, gas production from shale formations has grown to over 30% of the U. S. supply, and continues to grow. This is great news in every possible way – natural gas is the cleanest burning fossil fuel, it yields the least CO_2, and it is low cost, thanks to its newfound abundance in unconventional reservoirs."

Sincerely yours,

A D Hill

A. D. Hill

Mailing Address:
3116 TAMU
College Station, TX 77843-3116
Web - http://www.pe.tamu.edu

Department Head Office:
507 Richardson Building
College Station, TX 77843-3116
Tel. 979.845.2244 Fax 979.862.6579

Senator WHITEHOUSE. Thank you very much, Professor Hill.

Just to put this into perspective, why is it that we are concerned about fugitive methane?

Mr. HILL. Why is it? I think the primary concern is its role as a greenhouse gas.

Senator WHITEHOUSE. And its role as a greenhouse gas is what?

Mr. HILL. I am sorry, sir?

Senator WHITEHOUSE. Its role as a greenhouse gas is what?

Mr. HILL. Well, it has a greater effect on a per mass basis, much greater effect, apparently, than CO_2 as a greenhouse gas.

Senator WHITEHOUSE. Unless it is burned.

Mr. HILL. Yes.

Senator WHITEHOUSE. Than it is CO_2.

Mr. HILL. Yes.

Senator WHITEHOUSE. OK.

Mr. Boling, we have heard considerable testimony today about the value of the fugitive methane and there is a lawsuit in, I think, South or North Dakota over the loss to the mineral owners, alleging, again, very significant value. Given that the value is there and given that these companies tend to be in that business, why is it that the market itself hasn't solved this problem?

Mr. BOLING. I think that really depends on the situation. With respect to the Bakken, a lot of that gas is flared simply because there is not sufficient infrastructure in place to allow the gas to be economically gathered and sold. Obviously, at some point in time the volumes that get flared become very, very significant and something needs to be done, but I think that is really the answer to that question, is that the infrastructure is not there to support it.

Senator WHITEHOUSE. And how about the losses during normal production, the ones that were underestimated by EPA and shown to have been larger by the UT study that are further along in the process? That wasn't all lack of infrastructure, correct?

Mr. BOLING. That is correct.

Senator WHITEHOUSE. And why do you suspect it is happening in those cases, where the lack of infrastructure isn't the explanation?

Mr. BOLING. Well, I think that one of the issues, really, is I know that it does sound like a no-brainer, so to speak, that if it is going to make everyone money, why wouldn't you do it, but that presupposes you are not in a capital-constrained environment in terms of the investments being made by industry. And, in certain cases, if they feel like those dollars can go into things that can probably make them more money, they may not necessarily do it.

Senator WHITEHOUSE. Got it.

Dr. Allen, on balance, I gather, your study has come moderately close to supporting the EPA's overall numbers, but it shows dramatic differences in the place within the production sector where the leaks are taking place. Can you comment on the difference between potential and actual methane emissions from hydraulically fractured wells?

I ask unanimous consent to have, for the record, an exhibit that has gone up to your right side that you can see that shows the EPA 2011 numbers and the numbers from your report, and obviously it is a dramatic reduction in the top line, completion flowbacks from hydraulic fracturing.

Mr. ALLEN. Thank you for that question, Chairman Whitehouse. In our work, and also in the EPA national inventory, potential emissions are defined as methane that might get into the atmosphere. So in the context, for example, of completion flowbacks, it would be the methane that leaves the wellhead. If all of that is released to the atmosphere, then those potential emissions become the actual emissions. For completion flowbacks, what we found was that our measurements of what was leaving the wellhead were actually quite similar to EPA's estimates of potential emissions.

What we found was that when reduced emission completion equipment was in place, it was very effective in reducing those actual emissions to the atmosphere, hence, leading to this large reduction. So the potential emissions are mitigated by control technologies, and the difference between what gets into the atmosphere and the potential emissions depends on how widely those control practices are applied and how effective they are.

Senator WHITEHOUSE. We have heard testimony that these control technologies are both fairly common, not complicated, not complex, and also highly effective. Can you confirm that testimony from the point of view of your study?

Mr. ALLEN. Our study definitely confirms that reduced emission completions are highly effective. We can comment on the data that we measured. We went to 27 completion flowbacks. For two-thirds of those we found this type of equipment in place. This was for the nine companies that agreed to participate in our study. So, in this case, what we observed was that two-thirds of the flowbacks had this reduced emission completion equipment in place.

Senator WHITEHOUSE. Thank you.

We can do a second round, but I will abide by the timing and yield to our ranking member.

[The referenced information was not received at time of print.]

Senator INHOFE. Thank you, Mr. Chairman.

One of the issues that you reveal is that the emissions from pneumatic pumps were higher than previously thought. Is this something the industry recognized?

Mr. SMITH. No, I am not precisely sure that industry anticipated these results, Senator.

Senator INHOFE. All right. How much do you think is a maintenance issue versus an equipment issue?

Mr. SMITH. Well, I think, not being a participant in the study, I am not certain whether or not maintenance practices were evaluated by the team as a cause for the difference between kind of published emission rates and what was measured in the field, but I do know that this equipment, when it is installed in the field, it is subjected to pretty harsh conditions and maintenance needs to be an element to keep the equipment working as it is designed.

Senator INHOFE. And I would assume, then, Devon and you might also, Mr. Boling, agree with this and the rest of industry. Do you really think you need regulations to motivate these changes that are being talked about today?

Mr. SMITH. Is that a question to me?

Senator INHOFE. It is a question, yes, to you, Mr. Smith. In other words, doesn't it inure to your benefit to do this without regulations?

Mr. SMITH. As I mentioned in my testimony, a lot of the control technologies that have been discussed today are already being conducted by industry, and we have data from industry that suggests that, for instance, green completion equipment is being deployed very consistently across the industry. So the incentive, I think, to employ these control technologies is already there. I think an important thing to recognize is that, and I think this is maybe a little counterintuitive to some, but I think there is some belief that in this condition of low gas prices, that because gas is maybe not worth so much, that companies aren't paying as much attention to leaks of it.

But in reality, the inverse is really true, because if you consider a company needing to make profits from these wells, the only way that a company can offset our operating costs of these wells is to really, if you will, scrape the bottom of the barrel to really capture and sell every cubic foot of gas that we can. Otherwise, if we can't offset the operations costs of these wells, because, of course, operations costs are independent of what gas prices are, to a large part. If we can't offset our operations costs, then these wells are operating at a loss.

So even in conditions of low gas prices there is a strong incentive for energy companies to capture every cubic foot of gas that they can.

Senator INHOFE. Yes, that is right. Of course, you heard my comments in opening statement. I talked about the benefits of increasing our exports that would put us in a position. Right now you have huge supply, but the demand is down. This could change that around so that you would be in a position, and Mr. Boling, you would be in a position to have the benefits of the profits to make these changes that might not be economically feasible at today's market. Is that inaccurate? I have been trying to make the case and I have made some talks on the floor about exporting LNG.

Mr. SMITH. And this kind of demand certainty that would surround LNG export. Again, I think the incentive for operators to reduce leaks is maybe not so much driven by our forecast for demand certainty as much as it is about really trying to maximize profits and really, again, in these low conditions of gas prices, to certainly generate enough revenue to offset our operating costs in many areas.

Senator INHOFE. I got the impression, Dr. Gowrishankar, that you had said there is technology out there that some of these companies are not using, and the question I am asking them is it because the volume they are dealing with doesn't justify the cost of making these changes.

Mr. GOWRISHANKAR. Our analysis suggests that potentially the primary reason for them not being used more widely goes back to the question of capital constraints and other strategic initiatives that may potentially make more sense for the companies.

But in our view, these standards that require the control of these emissions make sense; they are profitable and that, I think, is pretty much undeniable. They are profitable and cost-effective and they, therefore, must be used to control these emissions. And there is no evidence to suggest that it is being used widely. There are some companies that are doing it, but voluntary action has not been sufficient.

Senator INHOFE. So you are contending that we need regulations to force that?

Mr. GOWRISHANKAR. Yes. We think regulations must be in place to level the playing field, fix the market failure, and ensure that these standards are adopted across the country by all producers; not just the leading ones, but everybody.

Senator INHOFE. If you don't mind my going a little bit longer, because I won't be able to stay for a second round. Just one other question.

Dr. Hill, from what I understand, a portion of the Federal royalties from the oil and gas operations goes toward ongoing research on oil and gas resources. We have talked about this for a long period of time. Because of this, the Federal Government has actually played a big role in collaborating with industry to unlock the shale revolution. But the program that manages the selection of the projects to fund expires next year. Can you tell us how extending the program will help foster voluntary collaboration and innovation, the benefits that would come with that?

Mr. HILL. Yes, Senator. I would be happy to. The program you are mentioning is called the Research Partnership to Secure Energy for America. It has been underway, it is in its seventh year now and this program has funded $50 million a year of research from royalty funds, Federal royalty money to support research on unconventional resource development, shale primarily, and the second major area is deepwater oil and gas development. This has been a very successful program; it supports research at many universities across the country, educated a lot of engineers for this burgeoning industry and helped a great deal in developing the technology that has led to these efficiencies.

There is a lot more to be done. A lot of the work that the RPSEA, as it is referred to, program is conducting right now is aimed more to the environmental side, a lot of studies on water usage, for example, minimizing fresh water usage and fracturing operations. So it is a program that has done a lot for this country, a lot for this development of shale gas and oil in particular.

Senator INHOFE. Do you think this should be reauthorized? We have a lot of good programs, Mr. Chairman, of cooperation. Partnership and Wildlife is one that has been very, very successful. This is another example.

Mr. HILL. Yes. I think it would be wonderful if this could be reauthorized.

Senator WHITEHOUSE. Senator Vitter.

Senator VITTER. Thank you.

Thank you all very much. Very impressive panel, particularly given that a UT and an A&M presence sat at the same table, albeit separated.

[Laughter.]

Senator VITTER. I want to go back to the sort of summary of the study. I know none of you have said this, but make sure there is no misconception of it. In a sense, the overall summary could be

EPA was way off in terms of estimates about the fracking process. They underestimated leakage from pneumatic devices, et cetera, and overall they were in the ballpark, maybe 10 percent off. But I want to make sure everybody agrees. The subcategories do matter in terms of policy and responsible policy and moving forward. It is certainly important that we understand where the problem is or the opportunity for improvement is and where it doesn't. Does everybody agree with that?

Dr. Allen. Everybody can respond.

Mr. ALLEN. Thank you, Senator Vitter. We feel the major contribution of our study is identifying where the major emissions are so whatever action is appropriate can be taken based on measurements of where the emissions are, and what we found was emissions from hydraulic fracturing completion flowbacks are very low when reduced emission completion equipment is in place and pneumatics were higher than we expected.

Senator VITTER. So does everybody agree that those subcategories absolutely matter and we have a lot to learn from those specific subcategory conclusions, even if it is some sort of general wash within 10 percent overall?

Mr. BOLING. I agree that the subcategories are very important. I would caution, however, that when we are talking about the emissions and conclusions to be drawn from the study, while it is clear that EPA's estimates of the actual, net emissions were much higher than the study, when you talk about potential emissions, as was mentioned previously, the potential emissions are pretty comparable. So it really is a question of production characteristics of the well and the period of time that the well is allowed to flowback. And if you get into a situation where the well either is not flowed back for a long period of time or you have REC completions, then you will have much less net emissions, even though the potential emissions could still very well be the same.

Senator VITTER. Right.

Mr. Smith, I think as early as 2010 Devon had initiated a project aimed at reducing emissions from pneumatic controllers, one of those specific areas we have been talking about. Can you go into a little detail about what you and other industry leaders have been doing there voluntarily?

Mr. SMITH. Yes. At Devon, we are proud to have written, as far as I know, the only carbon methodology for creating fungible emission credits from emission reductions in the oil and gas sector, and we did that with a methodology for the retrofit of pneumatic controllers. So it is taking high-bleed pneumatic controllers out of service and replacing them with low-bleed pneumatic controllers. And that methodology is available to the public, so any industry could use that and establish carbon credits for it.

The topic about what else we are doing to reduce methane emissions, unfortunately, we don't have near enough time to take you through that, but I will say that in addition to focusing on reducing emissions from pneumatic controllers, Devon was one of the pioneers in green completion reductions, one of the earliest companies that were doing green completions, so we are very familiar with that; we do it everywhere in our operation.

The other thing we do is that we have surveyed our operation. We don't have a wet seal on any one of our compressors. And without going into a bunch of technical detail about what a wet seal is, it is a much higher emitting device than a dry seal. So we don't have any wet seals in our operation.

Also we are really centralizing a lot of our production equipment so that some of the control equipment that is outside of its operating range at individual well sites is now feasible when you kind of aggregate more equipment together. So we are doing a lot of things, and not just us, but industry is doing a lot of things to be proactive in reducing methane emissions voluntarily.

Senator VITTER. Great. Thank you all very much.

Senator WHITEHOUSE. Thank you, Senator.

I would like to call up a chart that a smaller version I will make a part of the record, without objection. This is based on EDF information. I think Dr. Allen is familiar with it; perhaps Dr. Gowrishankar is as well. And what it shows is the ratio between the amount of fugitive methane that is released and how natural gas competes with other fuels in terms of being a better or worse carbon alternative, environmental alternative.

And you will see that although we are talking about very, very low numbers, 0.42 percent, we are dealing with very low numbers here. If you have 1 percent emitted of natural gas, not burned, but just emitted, then you don't break even with heavy duty diesel, I can't even read it, the lines are so close, it looks like for about 40 years. And if you are emitting 2 percent, you don't break even with gasoline for 40 years. And if you go to 4 percent, then you don't break even even with coal for 40 years.

So the question of how much methane gets away is vital to protecting, frankly, the marketing position of natural as against competing fuels in the minds of a public that is increasingly sensitive to these concerns. So I hope that this helps explain why we are so concerned about this and why I think this is a great opportunity for the industry and for the environmental community and Congress to all work together to solve this problem, because if worse gets out that if it is leaking in substantial amounts and that is causing natural gas to have to reverse a lot of the things that folks like the ANJ are saying all the time about the environmental value of natural gas compared to other fuels, then that is going to have, I think, an unfortunate effect on the market and on the credibility of the gas industry and so forth.

So I think it is really important that we get this right. I think the fact that the technology is as well established as it is, particularly through the leading companies, and I want to particularly recognize Devon and Southwestern for being here, is a very good sign. And the fact that even though it might not be the highest return in use of capital, the fact that it is a net positive use of capital for companies shows that this is the type of regulation that really, in fact, can be a win-win.

So I thank everybody for being here.

Just to make sure that the record is completely clear, I have asked Professor Hill this question, but, Mr. Smith, on behalf of Devon Energy, why is it that we want to limit the fugitive emission of methane?

Mr. SMITH. Well, from a company standpoint, and, of course, I recognize the global warming potential of methane and all that, but from a business perspective it is a responsibility to our shareholders to produce as much from our wells as they are funding us to do that.

Senator WHITEHOUSE. And describe the other reason that doesn't affect your shareholders so directly, but affects the rest of all of us.

Mr. SMITH. It is recognized as a greenhouse gas, that is absolutely right. We certainly would not deny that.

Senator WHITEHOUSE. And it, if released, will do what?

Mr. SMITH. Well, maybe you are pushing me into an area that, first of all, I am not an expert.

Senator WHITEHOUSE. Generally. You are the environmental manager for a very big energy corporation.

Mr. SMITH. Right.

Senator WHITEHOUSE. I am not asking you complicated questions.

Mr. SMITH. It is not a complicated question.

Senator WHITEHOUSE. Methane in the atmosphere does what?

Mr. SMITH. It is believed to cause global warming.

Senator WHITEHOUSE. Because it traps solar heat.

Mr. SMITH. Traps heat.

Senator WHITEHOUSE. All right.

One last question. When Senator Inhofe was asking, I guess, Mr. Smith about the maintenance versus equipment question, Dr. Allen, you were making notes as if you wanted to add something. I am not sure if you were just making notes. Did you have anything to add to that discussion or are we all set here?

Mr. ALLEN. No, I just make notes.

Senator WHITEHOUSE. OK, terrific. Then I won't press anything further.

Let me just thank all of you very much. This has been a very helpful panel and, Dr. Allen, the work that you have done obviously has made a very significant impact and I hope will help inform this policy debate. A lot of hard work went into it. I appreciate it very much.

Mr. Boling, thank you for the forward stance that Southwestern has shown and the very powerful way that you have brought industry and environmental leadership together in a way that I think does have this win-win potential. I am grateful to both of you.

Dr. Gowrishankar, thank you for your research with NRDC.

To our witnesses from Devon and from Texas A&M, again, thank you both for the expertise you brought to this hearing.

The hearing record will remain open for Senators to submit any written questions for 2 weeks. You think you are free of us, but you are not quite free; we might come after you with written questions for another 2 weeks. If you would be kind enough to reply to those questions, we obviously would be very grateful.

With that, the hearing is adjourned. Thank you all so much.

[Whereupon, at 4 p.m. the Subcommittee was adjourned.]

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