

ABOUT THE AUTHORS

MARY LASHLEY BARCELLA, IHS CERA Director, follows North American natural gas markets, focusing on long-term outlooks, pricing, economics, and policy. Recent research includes water issues in natural gas production, scenario analysis, and the role of natural gas in a carbon-constrained environment. She coauthored the IHS CERA Multiclient Study *Fueling North America's Energy Future*. Dr. Barcella has 30 years' experience in energy market, policy, regulatory, investment, and geopolitical analysis, as well as macroeconomic forecasting. She has provided consulting services to government and industry clients focusing on natural gas pipeline regulation, energy market analysis, and energy modeling and statistics. Before joining IHS CERA she held positions at the American Petroleum Institute, the American Gas Association, and several energy consulting firms. She served as managing editor for *Geopolitics of Energy* and on the editorial board of *Energy Politics*. She was a founding member of the International Association for Energy Economics and is also a member of the National Association for Business Economics and the American Economic Association. Dr. Barcella holds a BA magna cum laude from Vanderbilt University and an MA and a PhD in economics from the University of Maryland.

SAMANTHA GROSS, IHS CERA Director, specializes in helping energy companies navigate the complex intersection of policy, environment, and technology. She is the manager of IHS CERA's Global Energy service. She led the environmental and social aspects of IHS CERA's Multiclient Study *Growth in the Canadian Oil Sands: Finding the New Balance*, including consideration of water use and quality, local community impacts, and aboriginal issues. Ms. Gross was also the IHS CERA project manager for *Towards a More Energy Efficient World* and *Thirsty Energy: Water and Energy in the 21st Century*, both produced in conjunction with the World Economic Forum. Additional contributions to IHS CERA research include reports on the water impacts of unconventional gas production, international climate change negotiations, US vehicle fuel efficiency regulations, and the California low-carbon fuel standard. Before joining IHS CERA she was a Senior Analyst with the Government Accountability Office. Her professional experience also includes providing engineering solutions to the environmental challenges faced by petroleum refineries and other clients. Ms. Gross holds a BS from the University of Illinois, an MS from Stanford University, and an MBA from the University of California at Berkeley.

SURYA RAJAN, IHS CERA Director, is an expert on North American natural gas supply. Mr. Rajan has more than 20 years of energy industry experience across the value chain in many sectors, including upstream exploration and production, completion technologies, tight gas operations, downstream commercial supply chain, project management, information technology, corporate management, and strategy. In addition Mr. Rajan is actively connected with the gas industry through ongoing research, analysis, publications and presentations, and participation in industry forums. His interests and analyses have included strategic workforce issues, international corporate alliance models, country entry risk assessment, and the digital oil field. Before joining IHS CERA he held senior posts with Marathon Oil Corporation and Schlumberger. Mr. Rajan is a certified Project Management Professional. He is an active member of the Society of Petroleum Engineers, where he serves on the Digital Energy Program Committee for the Annual Technical Conference and Exhibitions. Mr. Rajan holds a BS from the Indian School of Mines, Dhanbad, and an MS from the University of Kansas.

We welcome your feedback regarding this IHS CERA report or any aspect of IHS CERA's research, services, studies, and events. Please contact us at info@ihscera.com or +1 800 IHS CARE (from North American locations) or at customer.support@ihs.com or +44 (0) 1344 328 300 (from outside North America).

For clients with access to **IHSCERA.com**, the following features related to this report may be available online:
downloadable data (excel file format); downloadable, full-color graphics; author biographies;
and the Adobe PDF version of the complete report.

TERMS OF USE. The accompanying materials were prepared by IHS CERA Inc., and are not to be redistributed or reused in any manner without prior written consent, with the exception of client internal distribution as described below. IHS CERA strives to be supportive of client internal distribution of IHS CERA content but requires that (a) IHS CERA content and information, including but not limited to graphs, charts, tables, figures, and data, are not to be disseminated outside of a client organization to any third party, including a client's customers, financial institutions, consultants, or the public; and (b) content distributed within the client organization must display IHS CERA's legal notices and attributions of authorship. Some information supplied by IHS CERA may be obtained from sources that IHS CERA believes to be reliable but are in no way warranted by IHS CERA as to accuracy or completeness. Absent a specific agreement to the contrary, IHS CERA has no obligation to update any content or information provided to a client. © 2011, All rights reserved, IHS CERA Inc., 55 Cambridge Parkway, Cambridge, Massachusetts 02142, USA. No portion of this report may be reproduced, reused, or otherwise distributed in any form without prior written consent.

MISMEASURING METHANE: ESTIMATING GREENHOUSE GAS EMISSIONS FROM UPSTREAM NATURAL GAS DEVELOPMENT

KEY IMPLICATIONS

Although natural gas is acknowledged to be the cleanest-burning fossil fuel owing to its low carbon content, attention has recently focused on upstream emissions of methane during well drilling, testing, and completion operations. Because methane is a much more potent greenhouse gas (GHG) than carbon dioxide (CO₂), methane that leaks or is purposely vented into the atmosphere is more harmful than the CO₂ that is produced when methane is flared. With the increase in natural gas production in recent years, primarily from shale gas, some sources, including the US Environmental Protection Agency (EPA), have suggested that upstream methane emissions are increasing.

- **EPA's current methodology for estimating gas field methane emissions is not based on methane *emitted* during well completions, but paradoxically is based on a data sample of methane *captured* during well completions.**
- **The assumptions underlying EPA's methodology do not reflect current industry practices.** As a result, its estimates of methane emissions are dramatically overstated and it would be unwise to use them as a basis for policymaking. The recent Howarth study on methane emissions makes similar errors.
- **If methane emissions were as high as EPA and Howarth assume, extremely hazardous conditions would be created at the well site.** Such conditions would not be permitted by industry or regulators. For this reason, if no other, the estimates are not credible.
- **EPA has proposed additional regulation of hydraulically fractured gas wells under the Clean Air Act.** For the most part, the proposed regulations are already standard industry practice and are unlikely to significantly reduce upstream GHG emissions. However, measured emissions could be significantly lower than EPA-inflated estimates. The greatest benefit of the proposed regulations is likely to be better documentation of actual GHG emissions from upstream natural gas development.

—August 2011



MISMEASURING METHANE: ESTIMATING GREENHOUSE GAS EMISSIONS FROM UPSTREAM NATURAL GAS DEVELOPMENT

by Mary Lashley Barcella, Samantha Gross, and Surya Rajan

METHANE: THE NEW FOCUS OF UPSTREAM EMISSIONS

Natural gas is widely recognized as the cleanest-burning fossil fuel. After processing, natural gas combustion emits no particulates and only half as much carbon dioxide (CO₂) as coal. Recently, however, attention has focused on the question of methane emissions from gas wells, processing plants, pipelines, and distribution networks. Methane is the largest component of natural gas, and methane emissions are of particular concern as it is a much more potent greenhouse gas (GHG) than CO₂, with a global warming potential (GWP) estimated at 25 times that of CO₂.*

Methane and CO₂ are the most important GHGs emitted from upstream natural gas operations. Methane is sometimes released to the atmosphere in small quantities before the well has been connected to a pipeline. Direct release of methane to the atmosphere is called *venting*. More often, methane is burned off at the well site, releasing CO₂ into the atmosphere in an operation known as *flaring*.

Production of natural gas from unconventional formations, including shale and tight sands, is increasing rapidly in North America. A single unconventional well typically produces much more gas (both initially and over its lifetime) than a conventional well, raising concerns that methane is being released into the atmosphere in greater quantities than in the past. Although emissions downstream of the wellhead are also of concern, much of the recent controversy has centered on emissions during well drilling, testing, and completion, and these operations are the focus of this Private Report.

SOURCES OF GHG EMISSIONS DURING WELL DRILLING AND COMPLETION

Understanding potential GHG emissions from well drilling and completion requires an understanding of the basic procedures of natural gas development. This section summarizes the process and the potential for emissions throughout.

During the process of drilling and completing a well, producers have three fundamental concerns:

- **Safety.** Natural gas is highly flammable. In the presence of ignition sources, such as electric devices, operating engines and machinery, or sparks, it can ignite. In certain concentrations mixed with air or in an enclosed space it can even explode. Any stray gas escaping to the atmosphere presents an imminent safety hazard to all people and equipment on location.

*The Intergovernmental Panel on Climate Change has increased its estimates of the GWP of methane from 21 times that of CO₂ in its second scientific assessment report published in 1995 to 25 times that of CO₂ in its fourth SAR published in 2008. The US Environmental Protection Agency (EPA) results discussed in this report still use a GWP of 21.

- **Health.** Natural gas poses health risks. Some constituents, such as ethane and propane, are heavier than air and can pool in shallow depressions. If natural gas is inhaled, reduced oxygen content can cause dizziness, fatigue, nausea, headache, and irregular breathing, and in severe cases loss of consciousness through asphyxia or even death. For humans and wildlife around a well location, the presence of natural gas in the atmosphere presents a serious health hazard.
- **Economics.** Millions of dollars are invested in drilling and completing an oil or gas well—as much as \$10 million for a shale gas well. All produced hydrocarbons represent potential return on that investment. Whenever possible, a producer will monetize every bit of produced gas by diverting to sales rather than allowing potential earnings to be lost.

In addition, owing to the higher GWP of methane, reducing methane emissions serves an important environmental goal as well the immediate goals of protecting people and property.

For all these reasons, releases of natural gas are carefully managed and minimized throughout the process of drilling and completing a well.

- **Drilling.** Very little gas makes it to the surface during the drilling process, and that gas is captured and flared off. The drilling “mud” that cools the bit and lifts cuttings to the surface is also designed to prevent high-pressure reservoir gas and oil from entering the wellbore and migrating up the annular space of the well, by virtue of the weight of the mud column in the wellbore. If there were accidental oil and gas inflow into the wellbore from the reservoir, it would be dangerous if any oil and gas were released on surface. To prevent this from happening, a blowout preventer (BOP) is installed on the surface. A BOP stack is designed to contain any pressure that does reach the surface, and this pressure is relieved by diverting stray gas to a flare stack. A controlled flame at the flare stack releases CO₂, but not methane, to the atmosphere.
- **Well completion.** Once the well is drilled, proper installation of casing and cement ensures that nothing enters the well except from the targeted gas-containing formation. During the process of hydraulic fracturing (also called fraccing), fraccing fluid (water, sand, and small amounts of chemicals) is pumped at high pressure into the target formation to create fissures that allow the gas contained in the formation to flow into the well. Unconventional gas wells are typically fraced in multiple stages, with a plug placed in the well between the stages. After the fraccing process is finished, these plugs and any other debris left in the well are drilled out.
- **Flowback.** After the well is cleaned up, the flowback process begins. Fraccing fluid flows from the wellbore to the surface, where it is diverted to an open pit or enclosed tank. Initially the flowback stream is primarily fluid, but over time this flow brings increasing fractions of reservoir gas as well. Gas contained in the flowback stream is flared, either through an igniter at the outflow of an open pit or a tank open at the top or by a flare stack attached to an enclosed tank. As soon as the gas flow is in

sufficient quantity and of adequate quality, it is sent by pipeline to processing facilities and then on to sales.

This process describes the ideal situation, minimizing venting and flaring and maximizing the amount of gas that goes to sale. A number of circumstances and inefficiencies can arise that result in greater GHG emissions.

Under some conditions, natural gas produced during flowback cannot be diverted to sales lines. Early production may contain high proportions of CO₂ or nitrogen that were injected during fracking or well cleanup or at flow kickoff. These and other contaminants may make the gas stream unacceptable for transportation pipelines. In such cases the gas may have to be flared off until the flow stream meets pipeline specifications. When the flow of natural gas is sporadic and in very small proportions it may be hard to sustain a flame on a flare stack. In less common instances when flaring itself may be difficult, an operator may elect to avoid the overhead of flaring equipment and “cold vent” gas until the proportion and quality of gas in the flow stream improves and consistent sustained flaring is possible (see the box “Cold Venting”).

Sometimes scheduling delays occur in construction of the tie-in pipeline connections that would carry produced gas to gathering and sales pipelines. When the well has been completed and is flowing, shutting in the well can be harmful to its productivity. Therefore

Cold Venting

The term *cold venting* describes the controlled release of small quantities of unflared natural gas to the atmosphere. Most of the fluid that flows out of the wellbore immediately after hydraulic fracturing is water. After the wellbore has purged itself of the initial column of fluid it contained at the end of pumping, a milestone referred to as “bottoms-up” in industry jargon, additional flow coming out of the wellhead is typically still mostly water that was pumped in for the frac treatment, but some traces of formation fluid—including water, natural gas, and liquid hydrocarbons—may also begin to appear at the surface. Typically these pockets of gas are small volumes, contain poor quality natural gas in very small concentrations, and contain large proportions of inert gases such as CO₂ or nitrogen that were used during the fracking process.

In cold venting, the flow stream is directed to a device called a gas-buster—essentially a cylinder perforated on the outside and containing a series of baffle trays on the inside. The baffle trays help separate gas from the water, and the perforations on the cylinder then allow the gas to dissipate into the air outside.

Cold venting is no longer industry standard practice in oil and gas operations, although it was common as recently as a decade ago. A few operators have continued to use it during drilling and production in spite of the safety risk it poses, mainly to save on rental charges associated with separation equipment and flare stacks. There have been reported instances where, close to populated settlements, flaring was considered aesthetically unacceptable, and cold venting was adopted as a preferred alternative. In oil and gas processing, cold venting may be used to release unexpected pressures from enclosed storage vessels that could otherwise pose a critical safety hazard. Awareness of the harmful effects of cold venting has caused the practice to fall out of favor. EPA’s proposed regulation of completion of fraced gas wells would prohibit the practice in most cases.

an operator may prefer to allow gas flow to continue but flare the gas until pipeline tie-in can be established. This is certainly not an ideal case for the operator, and operators make every effort to have tie-in lines completed by the time a well is producing.

The flaring process converts methane into CO₂, a much less potent GHG. However, small amounts of methane may escape into the atmosphere during flaring because the combustion efficiency of flares is not 100 percent. Citing a Gas Resources Institute (GRI) study, EPA assumes that 2 percent of the methane sent to flare escapes into the atmosphere.

In addition, flowback water contains some dissolved methane. Methane has a very low solubility in water, about 35 milligrams per liter at surface temperature and pressure conditions. When flowback water is pumped into open pits, dissolved methane can evaporate into the atmosphere. Although these emissions are very small, open-pit flowback has been losing favor as more and more operators move toward enclosed tanks.

In addition to emissions at the well site, most of the CO₂ contained in natural gas must be removed to bring the gas up to pipeline quality. Generally this is done at the processing plant, where natural gas liquids (NGLs) contained in the gas stream are also removed. Data from both EPA and the US Energy Information Administration (EIA) suggest that approximately twice as much CO₂ is removed from gas at processing plants than is released in the field (primarily) during flaring.

METHANE AND CO₂ EMISSIONS FROM UNCONVENTIONAL GAS PRODUCTION

Initial production rates (IPs) for shale wells are many times greater than those for conventional wells. Some observers suspect that the growth in shale gas production may have been accompanied by an increase in methane emissions.

In the Background Technical Support Document *Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry* released in 2010, EPA greatly increased its estimate of methane emissions from various upstream gas activities. Earlier estimates were based on a 1996 study conducted jointly with GRI. For methane emissions during well completions, EPA created separate categories for conventional and unconventional well completions and increased estimated emissions for both categories. EPA's previous emissions estimate was 0.02 metric tons of methane per well completion. EPA now proposes a much higher estimate of 0.71 metric tons per conventional well and 177 metric tons per unconventional well completion.

EPA used these new emissions factors to revise historical GHG emissions estimates. As a result EPA's estimate of 2006 total upstream GHG emissions from the natural gas and petroleum industries more than doubled, from 90.2 million metric tons of CO₂-equivalent (mtCO₂e) to 198 mtCO₂e.*

*US Environmental Protection Agency, *Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry: Background Technical Support Document, 2010*, pp. 9–10.

In addition to methane, CO₂ and small amounts of other GHGs are also emitted during gas well completions and other upstream operations. However, EPA has not proposed revisions to the methodology for estimating upstream emissions of these GHGs.

New EPA Methodology Overstates Methane Emissions

EPA's new methodology estimates that each unconventional gas well completion emits 9,175 thousand cubic feet (Mcf) of methane, of which 51 percent is assumed to be flared and the rest vented. But here is the basic problem: EPA's analysis relies on assumptions that are at odds with industry practice and with health and safety considerations at the well site. IHS CERA believes that EPA's methodology for estimating these emissions lacks rigor and should not be used as a basis for analysis and decision making.

Where did this higher estimate come from? EPA derived the emissions factor from two slide presentations at Natural Gas STAR technology transfer workshops, one in 2004 and one in 2007.* These two presentations primarily describe methane that was captured during "green" well completions, not methane emissions. EPA assumes that all methane captured during these green completions would have been emitted in all other completions. This assumption does not reflect industry practice.

In addition to the inappropriate use of the Natural Gas STAR reports, the EPA estimate of methane emissions essentially averages four data points, each of which was generated on the basis of multiple assumptions and rounded to the nearest hundred, thousand, or ten thousand Mcf prior to averaging. As EPA explains in its *Background Technical Support Document*,

- "One presentation reported that the emissions from all unconventional well completions were approximately 45 Bcf [billion cubic feet] using 2002 data.... The...high pressure, tight-formation wells emitted...44.7 Bcf. Since there is great variability in the natural gas sector and the resulting emission rates have high uncertainty; the emission rate per unconventional (high-pressure tight formation) wells were **rounded to the nearest thousand Mcf ...6,000 Mcf/completion**" [emphasis added].** EPA's derivation of this result is unclear but appears to rest on a sequence of assumptions about wells drilled in 2002 that seem to be inconsistent with EIA data.
- "The same Natural Gas STAR presentation provides a Partner experience which shares its recovered volume of methane per well.... Again, because of the high variability and uncertainty associated with different completion flowbacks in the gas industry, this was **estimated only to the nearest thousand Mcf—10,000 Mcf/completion**" [emphasis added].*** This data point is based on 30 wells drilled in the Fort Worth Basin.
- In the same presentation, "a vendor/service provider [reported] the total recovered volume of gas for 3 completions.... Again, because of the high variability and uncertainty associated with different completion flowbacks in the gas industry, this was **rounded**

*EPA, "Green Completions," Natural Gas STAR Producers' Technology Transfer Workshop, September 21, 2004; and EPA, "Reducing Methane Emissions During Completion Operations," Natural Gas STAR Producers' Technology Transfer Workshop, September 11, 2007.

**EPA, Background Technical Support Document, page 86.

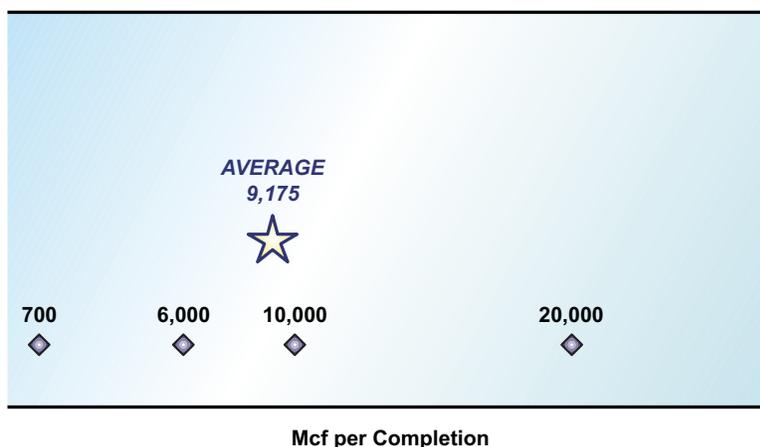
***EPA Background Technical Support Document, page 87.

to the nearest hundred Mcf—700 Mcf/completion [emphasis added].* This data point is based on three coalbed methane wells drilled in the Fruitland Formation in Durango, Colorado.

- “The final Natural Gas STAR presentation with adequate data to determine an average emission rate also presented the total flowback and total completions and recompletions. Because of the high variability and uncertainty associated with different completion flowbacks in the gas industry, this was **rounded to the nearest 10,000 Mcf—20,000 Mcf/completion**” [emphasis added]**. This data point is based on 1,064 wells completed from 2002 through 2006 in the Piceance Basin.
- “This analysis takes the simple average of these completion flowbacks for the unconventional well completion emission factor: **9,175 Mcf/completion**” [emphasis added] (see Figure 1).***

To summarize the math, the final emissions factor of 9,175 Mcf per completion that is assumed to apply to all unconventional wells completed in the United States was calculated as the simple average of four (unaudited) data points. EPA rounded each data point to the nearest hundred, thousand, or ten thousand Mcf as a way of handling the “high variability and uncertainty” in the industry. These four data points represent very different sample sizes (from three to thousands) and underlying data quality. A simple average of these points does not provide a rigorous estimate of industry emissions.

Figure 1
EPA’s Analysis to Determine Methane Emissions



Source: EPA.
 10802-4

*Ibid.
 **Ibid.
 ***Ibid.

Moreover the second and third data points do not refer to methane emissions at all. Rather they represent the amount of gas that was recovered during green completions of natural gas wells—operations designed to capture as much methane as possible during the well completion process. The fourth data point describes operations in which more than 90 percent of flowback gas was recovered and sold. In other words, well completions described in three of the four data points used to derive the average emission factor of 9,175 Mcf per completion emitted little or no methane. EPA’s assumption that all methane recovered from these wells would otherwise have been flared or vented is questionable at best, given the industry practices described earlier and operators’ financial interest in sending gas to sale as soon as possible.

EPA’s assumption that 49 percent of gas is vented and 51 percent is flared is also based on a number of assumptions that do not reflect current industry practice. EPA calculated this ratio as follows.

“Some states regulate that completion and re-completion (workover) flowbacks must be flared or recovered. Industry representatives have shared with EPA that flaring of completions and workovers is required in Wyoming; however, it is not required in Texas, New Mexico, and Oklahoma. EPA assumed that no completions were flared in the Texas, New Mexico, and Oklahoma [sic], and then took the ratio of unconventional wells in Wyoming to the unconventional wells in all four sample states to estimate the percentage of well completions and workovers that are flared. EPA assumed that this sample was indicative of the rest of the U.S. This ratio was estimated to be approximately 51%.”*

In other words, the assumed ratio of methane flared versus vented is based on the ratio of unconventional wells in Wyoming (where flaring is required) to wells in Texas, New Mexico, and Oklahoma (where flaring is not required) and extrapolated to the entire United States, a questionable assumption. Even more questionable is the use of a ratio of *wells* to make inferences about the production of *volumes*. The implicit assumption is that production per well is approximately equal not only across the states of Wyoming, Texas, New Mexico, and Oklahoma, but indeed also across the entire United States. Finally, EPA assumed that flaring did not take place if it was not required and that pure methane was vented to the atmosphere. This assumption is clearly at odds with the industry practices described above. The State of Texas has since passed regulations that require monitoring and control of fugitive emissions including methane, ethane, and volatile organic compounds (VOCs) in the Barnett Shale area. Use of equipment to capture and reclaim VOCs is required, any fugitive emissions must be monitored and reported, and any violations must be corrected under the new Texas Commission on Environmental Quality (TCEQ) regulations.**

In summary EPA made two crucial errors in its estimate of methane emissions.

*EPA Background Technical Support Document, page 88.

**“[Texas implements new emissions rules for Barnett Shale play](#),” Platts news report January 28, 2011; [TCEQ Barnett Shale Area website](#); see the IHS CERA Private Report *Texas Positions Barnett Shale as Role Model for Air Quality Regulations*.

- **EPA based the estimate on a simple average of four data points taken from presentations at technical conferences in 2004 and 2007.** Three of these data points describe methane captured for sale, not methane emitted.
- **EPA assumes that gas produced during completion is vented, rather than flared, unless flaring is required by state regulation.** This assumption is at odds with industry practice and with safe operation of drilling sites.

As a result of these questionable assumptions, the overall amount of methane that EPA assumes is emitted during well completion activities does not pass a basic test of reasonableness. Methane emissions of 9,175 Mcf per well, if vented during a few days of well completion procedures, would create a toxic and hazardous environment around the well site. That serious accidents are rare in gas plays suggests that upstream emissions do not regularly rise to such dangerous levels. EPA's estimate certainly does not represent the *average* level of emissions from well completions.

The EPA calculations also ignore that any emissions occurring during flowback do so only in the first few days of the life of the well. Once completed, no further fugitive emissions occur for the 20- to 40-year life of the well except during extraordinary maintenance events such as workovers, which may be undertaken to address productivity issues. In any given year only about 20 percent of the total gas supply in the United States comes from newly drilled wells.

IHS CERA estimates that in 2010 a total 10.7 Bcf per day of gas was produced from gas wells drilled that year. This is about 18 percent of the 58.2 Bcf per day of total gas produced in the US Lower 48. Even if each well had vented all of its eventual daily production of methane during a ten-day flowback period—which, as indicated previously, was not the case—the total methane emitted during flowback procedures in 2010 would have been 107 Bcf. Not only is this only 0.5 percent of the more than 21 trillion cubic feet (Tcf) of gas produced in the US Lower 48 in 2010, it represents only 43 mtCO₂e of methane emissions—far lower than EPA's estimated level of 130 million tons of methane emissions from natural gas field production in 2009. And for reasons already discussed, this is a gross overestimate, because first, wells in flowback do not contain methane in quantities equal to their post-completion daily production, and second, most of the methane in flowback is flared, if not captured for sale.

Finally it should be noted that owing to the greater productivity of shale gas wells, fewer wells now have to be drilled to produce a given quantity of natural gas. EIA reports that 33,331 gas wells were drilled in the United States in 2008 and total US gas production that year was 55.1 billion cubic feet (Bcf) per day.* In 2010 only 18,672 gas wells were drilled, but production rose to 59.1 Bcf per day. The reduction in total wells drilled at least partially offsets any increase in emissions per well that may result from the shift to shale gas development.

*Includes the US Lower 48 and Alaska.

A Cornell Study also Overestimates Methane Emissions

A controversial paper in the journal *Climatic Change Letters* by Robert W. Howarth, Renee Santoro, and Anthony Ingraffea of Cornell University also argues that emissions of methane during flowback from unconventional gas wells is much greater than previously estimated.*

This paper follows and extends the analysis of the EPA study. It considers methane emissions during flowback from five unconventional gas basins. Data for two of these basins (Barnett and Piceance) are the same as those used in EPA's analysis—the second and fourth data points described above. The paper uses similar data from presentations at EPA Natural Gas STAR workshops for two additional basins (Uinta and Denver-Julesburg).** Data for the fifth basin (Haynesville) is attributed to an IHS report.***

IHS data for the Haynesville Shale was misused and severely distorted in the Howarth paper. The analysis included wells that were not in the flowback phase at all; double-counted a particularly prolific well; and in the single case of a well tested during the flowback process, assumed that methane was emitted when in fact it was captured for sale, as clearly stated in the IHS report. Appendix 1 contains a letter sent to the editor of *Climatic Change Letters* in response to the misuse of IHS data. Appendix 2 contains an excerpt of the IHS report cited in the Howarth paper. Data for three of the other four basins were estimates of gas recovered from green completions, similar to the methodology used in the EPA analysis. Again, the assumption that *all* of this gas would otherwise have been vented or flared is unwarranted.

The Howarth paper states that methane emissions from unconventional gas wells average nearly 2 percent of the ultimate recovery of natural gas over the lifetime of the well (typically 20 years or more). By contrast, the authors estimate that flowback methane emissions from a conventional gas well average only 0.01 percent of ultimate recovery. They attribute the greater amount of methane emissions from unconventional wells to the large volume of fracturing fluids that flow back from these wells and the methane that accompanies the fracturing fluid.

The Howarth estimates assume that daily methane emissions throughout the flowback period actually exceed the wells' IP at completion. This is a fundamental error, since the gas stream builds up slowly during flowback.

Compounding this error is the assumption that *all* flowback methane is vented, when industry practice is to capture and market as much as possible, flaring much of the rest. Vented

*Robert W. Howarth, Renee Santoro, and Anthony Ingraffea. "Methane and the Greenhouse-gas Footprint of Natural Gas from Shale Formations," *Climatic Change Letters*, March 13, 2011.

**J. Samuels, *Emission Reduction Strategies in the Greater Natural Buttes*. Anadarko Petroleum Corporation. EPA Gas STAR, Producers Technology Transfer Workshop Vernal, Utah, 23 March 2010, http://www.epa.gov/gasstar/documents/workshops/vernal-2010/03_anadarko.pdf and K. Bracken (2008) "Reduced Emission Completions in DJ Basin and Natural Buttes." Presentation given at EPA Gas STAR Producers Technology Transfer Workshop. Rock Springs Wyoming, 1 May 2008. <http://www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/rocksprings5.pdf>

***M. Eckhardt, B. Knowles, E. Maker, P. Stark, *IHS US Industry Highlights, February–March 2009*. (IHS) Houston, Texas.

emissions of the magnitudes estimated by Howarth would be extremely dangerous and subject to ignition. The simple fact that fires are rare in all gas-producing areas suggests that this analysis grossly overestimates the quantities of methane that are leaking uncontrolled into the atmosphere at the well site.

PROPOSED EPA REGULATIONS LARGELY FOLLOW INDUSTRY PRACTICE

On July 28, 2011, EPA proposed new source performance standards under the Clean Air Act that would regulate air emissions during the completion phase of hydraulically fractured gas wells. The proposed regulations require green completion techniques—recovery of gas for sale as soon as technically feasible—and flaring of any produced gas that is not suitable for sale. The regulations also require advance notification of well completions and annual reports that include the details of each well completed during the year and the duration of gas recovery, flaring, and venting at each well.

These proposed standards do not directly regulate emissions of methane or other GHGs. Instead they focus on emissions of sulfur dioxide and VOCs. However, the measures that reduce emissions of these pollutants have the additional benefit of reducing methane emissions as well.

The benefits of the proposed standards are based on EPA's overstated estimate of gas vented during well completion operations and are therefore also overstated in terms of reducing air pollution and emissions of GHG. However, many operators already follow the practices that the standard requires. Common industry practice is to capture gas for sale as soon as it is technically feasible. Gas that cannot be sold is generally flared rather than vented for safety reasons.

The proposed standards have the potential to codify good operating practice in the gas drilling industry. The data collection requirement could also provide much more reliable data on methane emissions from gas well completions, a potential benefit to all who seek to better understand GHG emissions from the industry.

A QUESTION OF VOLUME

The volume of gas vented or flared is a very small percentage of total gas production each year, and IHS CERA believes that EPA has greatly overestimated these volumes. Nonetheless even relatively minute amounts of gas emissions can have an environmental impact. Because the GWP of methane is so much greater than that of CO₂, it is important to develop better data on the amount of gas vented versus flared during well completions. The data collection portion of EPA's proposed regulations has the potential to be an important step in the right direction.

The environmental impacts of unconventional gas production have become a controversial public issue. Given the rapid growth of unconventional production, rigorous analysis of these effects is important. Such an analysis must be based on facts and clear understanding of industry practices. Recent estimates of the GHG emissions from drilling and completion of

unconventional gas wells do not meet this standard. EPA would do better to rely on a new, more appropriate data-driven methodology in addressing GHG emissions.

APPENDIX 1

COMMENT ON “METHANE AND THE GREENHOUSE GAS FOOTPRINT OF NATURAL GAS FROM SHALE FORMATIONS”

Philip H. “Pete” Stark, Vice President, IHS

It has come to my attention that an IHS report, of which I was a co-author, was mis-used and seriously distorted in an article published in *Climatic Change Letters*, “Methane and the Greenhouse Gas Footprint of Natural Gas from Shale Formations” by Robert W. Howarth, Renee Santoro, and Anthony Ingraffea. The article cites our report, *US Industry Highlights, February–March, 2009* (attached below), as the basis for their claim that 6,800 thousand cubic meters (Mcm)—or 240 million cubic feet (MMcf) of methane—is released to the atmosphere during a ten-day flow-back period from the Haynesville shale gas play. They go on to conclude that

“...the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing.”

Our report does not support their conclusion at all. Only one of the Haynesville wells in our report was measured during flow-back—the several days after drilling and fracking but before completion, during which time the drilling and fracking fluids are pushed back out of the well ahead of the gas. That well produced 14 MMcf of natural gas per day, *none of which was released to the atmosphere*. Our report clearly states that the well was “producing to sales.” In other words, the natural gas production was being captured and marketed. Here is the relevant excerpt from our report:

“Also in Woodardville field, Forest Oil said it completed its first horizontal Haynesville/Bossier Shale well in Red Rive Parish. The 1 Moseley “14H” was reported **producing to sales** at the daily rate of 14 million cu ft of gas equivalent through perforations at 12,800–15,260 ft while the operator was still cleaning up frac load.” (Emphasis added)

No methane from this well was emitted to the atmosphere, nor does the IHS report present any evidence of such methane emissions from any other well.

A copy of our full report is attached below.

Other serious, but less egregious misrepresentations of our report in the Howarth team’s article include

- An improper calculation of the average of the individual well flow rates discussed in our report.
- An improper attribution of the (improperly calculated) average flow rates from all the wells as occurring during flow-back operations. In fact, only one of the ten wells reported was measured during flow-back. The others were measured while the wells were being completed (capped and connected to pipelines).

We reported the results of nine gas well completion tests and one well tested during flow-back in the Haynesville Shale during late 2008. In calculating the average flow rates from the ten wells, the Howarth team made a simple error of double-counting the results from the most prolific well in our report. Specifically, we stated that

“The 5 Laxson was tested flowing almost 33.8 million cu ft of gas per day through fracture-treated perforations at 15,416–15,691 ft. Daily absolute open flow was calculated at more than 39.49 million cu ft.”

The average production from the 10 well tests was 18.4 MMcf per day, but if you include both the 33.8 MMcf per day Laxson test and the 39.49 MMcf per day open flow calculation for the Laxson well you get the 24 MMcf per day (or 680 Mcm per day) figure cited in the Howarth article. So the Howarth team apparently counted two production tests from a single well in calculating their average for the Haynesville. (By the way, the Laxson well is in the Bossier shale play, not the Haynesville, although the two plays overlap geographically to some extent.)

It is clear to me that Professor Howarth and his co-authors have not only misinterpreted our data but they have also claimed that the data support conclusions that in fact the data do not support. As I have documented in this comment, the IHS report referenced as the source of their data on methane emissions from the Haynesville only supports a conclusion that one Haynesville well tested during flow-back produced 14 MMcf per day, none of which was emitted into the atmosphere.

APPENDIX 2

EXCERPT FROM *IHS US INDUSTRY HIGHLIGHTS, FEBRUARY–MARCH, 2009*

Marc Eckhardt, Bob Knowles, Ed Marker, and Pete Stark.

Haynesville Shale: Numerous high-volume completions continue to be reported in the Haynesville Shale play of northwestern Louisiana, including a horizontal KCS Resources well that flowed nearly 19.1 million cu ft of gas daily. Located in Elm Grove field in the southern portion of North Louisiana’s Bossier Parish, the 6 Woodley “8” was tested through fracture-stimulated perforations at 11,384–15,450 ft. Less than a half-mile to the east in the same section is the company’s 3-Alt Osborne “8” which previously flowed 18.7 million cu ft of gas per day. Also nearby are the recently completed KCS-operated 4 Mack Hogan (14.7 million cu ft daily), 5 Roos “A” (14.6 million cu ft), 5-Alt Goodwin “9” (21.1 million cu ft) and 13 Elm Grove Plantation “30” (20.3 million cu ft).

In western Bienville Parish, Questar Exploration & Production has completed two horizontal Haynesville Shale wells in Woodardville field. The 1 Wiggins “36H” was tested flowing 7.2 million cu ft of gas per day through perforations at 12,695–16,182 ft. Just over two miles to the east is the operator’s 1 Golson “32H,” which flowed 20.9 million cu ft of gas daily through perforations at 12,590–16,577 ft. Questar is active at another Haynesville Shale test a mile and a half west of the 1 Golson. The 1 Shelby Interests “31H” was being production tested at last report.

Also in Woodardville field, Forest Oil said it completed its first horizontal Haynesville/Bossier Shale well in Red River Parish. The 1 Moseley “14H” was reported producing to sales at the daily rate of 14 million cu ft of gas equivalent through perforations at 12,800–15,260 ft while the operator was still cleaning up frac load. Forest holds approximately 2,800 net acres around the drillsite and approximately 140,000 gross (106,000 net) acres in the Haynesville/Bossier Shale play and intends to operate a two-rig program to drill 10–12 Haynesville/Bossier Shale wells and participate in two to three nonoperated wells during 2009.

St. Mary Land & Exploration also announced that it reached total depth at its first operated horizontal Haynesville Shale well. The company has a 90 percent working interest in the 2 Johnson Trust “1” in Spider field in DeSoto Parish. It was drilled to 15,264 ft, with a 3300-ft lateral. The company said its next planned Haynesville well is expected to be in Shelby County (RRC Dist. 6), where it has a sizeable acreage position.

Far from the Haynesville core in northwestern Louisiana, a high-volume Bossier well was recently completed by EnCana Oil & Gas in the eastern portion of East Texas’ Robertson County (RRC Dist. 5). The 5 Laxson was tested flowing almost 33.8 million cu ft of gas per day through fracture-treated perforations at 15,416–15,691 ft. Daily absolute open flow was calculated at more than 39.49 million cu ft. The new vertical producer was placed in John Amoruso field, which was opened by the operator in 2006. More than 50 Bossier wells were onstream at the end of 2008. ■