Comments Received during the Public Review Period on the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011

Commenter: Giles Ragsdale
AECOM

Comment: Table ES-10 has nearly identical data for the years 2009, 2010, and 2011 for most line items. Those data could be true but I'm skeptical due to the way the data changes for previous years.

Commenter: Michael J. Rush
Association of American Railroads

Comment: Would you please clarify a table in the latest draft? Table A-112 shows for "other emissions from rail electricity use" 77.7 Tg CO2 eq. Table A-111 for the previous year shows, for the same category, 0.1 Tg CO2 eq. Why has the number gone up so much? As an aside, the higher number doesn't seem correct – it shows almost double the CO2 eq emissions for electricity as it shows for diesel fuel.

Commenter: Arline Seeger
National Lime Association

Comment: To accurately generate national estimates of calcination emissions from lime manufacturing, the following information is necessary for each lime plant: the CaO and MgO content of each type of lime product (e.g., hi-calcium, dolomitic), lime kiln dust (LKD) and waste type (off-spec lime, scrubber sludge, etc) generated, and the quantity of each lime product, LKD and waste type produced.

Currently, under EPA's GHG Reporting Rule, this information is not reported to EPA, pending a review by the Agency as to whether it is Confidential Business Information. EPA has indicated it plans to finalize its review by 2015. Therefore, EPA's proposal to use 2011-2012 data to derive national estimates of calcination emissions from lime manufacturers is premature and the IPCC estimation techniques should be used with the modifications described below.

Suggested Enhancements to EPA's Current IPCC-Based Approach

The IPCC's output-based approach for estimating calcination emissions from U.S. lime products is highly accurate, but it significantly understates emissions from LKD and other byproducts/wastes generated in the United States, as explained below.

Lime Products: For both hi-calcium and dolomitic lime, IPCC's emission factor assumes that the average oxide content of lime is 95%. This is within 0.2% of the facility-level oxide content reported to NLA by its members for 2011, as illustrated below.

	CaO (%)	MgO (%)	Total Oxides %
High Calcium Quicklime	93.3	1.9	95.2
Dolomitic Quicklime	56.6	38.6	95.2

Likewise, the emission factors used by IPCC are very similar to the average emission factors of our member's lime products, as shown below.

	Emission Factor	
	IPCC	Emission Factor based on NLA Member Average Lime Oxide Content[1,2]
Hi Cal Lime	0.7455	0.7522
Dolomitic Lime	0.8675	0.8656

We calculated the difference in CO2 emissions using data reported by our members via the GHG Reporting Tool vs using the IPCC emission factors. As shown below, the difference is only 26,900 tons, a negligible 0.2% of lime product-related calcination emissions.

	Emission Factor		2011 Calcination Emissions from NLA Member Lime Products (rounded to the nearest 1000)	Understated Calcination Emissions Using IPCC Emission Factor	
	IPCC	NLA Member Emission Factor		Tons CO_2	% of Lime Related Emissions
Hi Cal Lime	0.7455	0.7522	11,560,000	11,850	0.1
Dolomitic Lime	0.8675	0.8656	3,262,000	15,050	0.1
			14,822,000	**26,900**	0.2

Lime Kiln Dust:

As NLA has previously reported to EPA's contractors, based on data reported to NLA from our members, emissions from generating LKD account for about 6% of calcination-related emissions from lime manufacturing (in 2011, it was 5.8%). Conversely, the IPCC multiplies lime product-related emissions by a "correction factor" of only 1.02 to account for LKD. The IPCC Guidelines acknowledge that this correction factor for LKD is borrowed from its chapter on cement, which in turn explains that the factor for cement kiln dust (CKD) is relatively low because most CKD is recycled back into the process.

By contrast, the lime industry does not recycle LKD back into the process, and thus borrowing such a factor to account for LKD-related calcination emissions is inappropriate.

EPA's reliance on the IPCC's LKD generation rate of 2% (rather than 6%) understates calcination emissions from our members alone by 557,800 tons. This is roughly 5.4% of our members' total emissions, and twenty times the understated calcination emissions described earlier for lime products.

Off-Spec Lime, Scrubber Sludge, and Other Wastes

The IPCC Guidelines do not appear to take into account calcination emissions resulting from wastes commonly generated at lime plants (e.g. off-spec lime that is not recycled, scrubber sludge). Again, based on 2011 data reported to NLA from our members, calcination emissions from production of such wastes account for approximately 1.7% of total calcination emissions, or 256,000 tons. To address this omission, we recommend that EPA multiply quicklime calcination emissions by a factor of 1.02.

Conclusion

Implicit in EPA's request for comments is the assumption that aggregating facility-level data reported to the GHG Reporting Tool is necessary to materially improve national estimates of calcination emissions from lime manufacturers. As noted above, lime manufacturers are currently not required to report the information needed to pursue this approach.

Nonetheless, the IPCC's approach is capable of generating reasonably accurate national estimates of calcination emissions from the lime industry, with just a few modifications. Lime related emissions account for the vast majority -- 93%, of calcination emissions from the lime industry. As shown above, based on data from companies producing over 98% of the commercial lime made in the United States, the IPCC-based approach generates an estimate of calcination emissions for the lime product itself that differs from the value generated by the Subpart S GHG Reporting Tool approach by only 0.2%.

Where the IPCC-based approach fails to generate accurate estimates of calcination emissions is for LKD and other byproducts/wastes produced at lime plants. This can be cured by multiplying lime calcination emissions by a factor of 1.06 to account for LKD, and by 1.02 to account for wastes generated at lime plants.

Commenter: David E. Brann

Electro-Motive Diesel Inc.

Comment: In table ES-7, the total 2011 transportation greenhouse gas (GHG) emission is 1,826.4 Tg CO2 Eq. However, in table A-112, the transportation total is given as 1,908.4 Tg CO2 Eq., and summing the figures for passenger and freight transportation in Tables A-114 and A-115 yields 1,274.4 + 535.8 = 1,810.2 Tg CO2 Eq. Does this arise from differences in accounting, or is there an error?

Comment: On page A-158, last paragraph, the 2011 GHG emission from passenger transportation modes is given as 1,302.1 Tg CO2 Eq. This is the 2010 figure from table A-114; the 2011 figure is 1,274.4 Tg CO2 Eq.

Comment: In Table A-114, the 2011 GHG emission from passenger rail is given as 5.9 Tg CO2 Eq., and in table A-115 that from freight rail is given as 42.0 Tg CO2 Eq. Summing those gives 47.9 Tg CO2 Eq. However, the total rail emission is given as 125.6 in table A-112. The latter figure includes 77.7 Tg CO2 Eq from rail electricity use. Why is the latter figure not broken out by freight and passenger uses? (In the 1990-2010 inventory, the passenger rail figure in Table A-113, 6.2 Tg CO2 Eq., and the freight rail figure in Table A-114, 40.0 Tg CO2 Eq., add to the total rail figure in Table A-111, 46.3 Tg CO2 Eq, within a rounding error. In the 1990-2010 inventory, the "Other Emissions from Rail Electricity Use" in table A-111 is 0.1 Tg CO2 Eq., versus the 2011 figure of 77.7. Frankly, the 77.7 figure puzzles me greatly; I would have expected the bulk of rail emissions to come from fuel combustion, not from the use of electricity.)

Commenter: William Herz

The Fertilizer Institute

Comment: Throughout the Draft Inventory, EPA indicates in the "Planned Improvements" section that the Agency will use greenhouse gas emissions data from the EPA Greenhouse Gas Reporting Program as a basis for improving emissions calculations. The EPA states that the Agency will assess how this data could be used to improve the overall method for calculating emissions and specifically assessing data to update emission factors and other calculations (see for example Ammonia Production section at 4-23 – 4-24).

TFI questions the efficacy of this methodology as opposed to harmonizing data to create a single report characterizing domestic greenhouse gas emissions. If, for example, all ammonia production facilities are required to submit emissions data under the Greenhouse Gas Reporting rule, then EPA has actual data from all domestic ammonia production facilities that can then be aggregated to characterize emissions data for that specific source category. With actual data, TFI does not see additional value form calculating emissions with or without updated emission factors.

Further, harmonization would allow the Agency to address additional issues of allocation of emissions across source categories, such as the issue of attributing CO2 emissions from non-fertilizer uses of urea to urea manufacturers (discussed in greater detail below), for accuracy and consistency.

TFI requests that EPA provide affected stakeholders with a plan for harmonization of Greenhouse Gas Reporting data and the Draft Inventory, including but not limited to, methodologies for incorporating reported data into the Draft Inventory as well as a consistent methodology for allocating CO2 emissions to downstream emission sources.

Comment: TFI remains concerned with EPA's methodology for distributing greenhouse gas emissions across end-use sectors. Specifically, in the section entitled "End-Use Sector Emissions of CO_2 from Fossil Fuel Combustion (p. 2-19)," EPA describes the methodology as follows:

"To distribute electricity emissions among economic end-use sectors, emissions from the source categories assigned to the electricity generation sector were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to retail sales of electricity (EIA 2010 and Duffield 2006). These three source categories include CO2 from Fossil Fuel Combustion, CH4 and N2O from Stationary Combustion, and SF6 from Electrical Transmission and Distribution Systems.

When emissions from electricity are distributed among these sectors, industrial activities account for the largest share of total U.S. greenhouse gas emissions (29.6 percent), followed closely by emissions from transportation (26.7 percent). Emissions from the residential and commercial sectors also increase substantially when emissions from electricity are included, due to their relatively large share of electricity consumption. In all sectors except agriculture, CO_2 accounts for more than 80 percent of GHGs, primarily from the combustion of fossil fuels."

Neither the Draft Inventory nor the associated Annex methodology allow for the discount of combined heat and power (CHP) and other onsite power generation. In contrast, the methodology employed for estimating CO_2 emissions from fossil fuel combustion does allow these downward adjustments as accounted for in the Industrial Processes chapter; including the conversion of fuels and exports of greenhouse gases and fuels consumed for non-energy uses.

However, no comparable adjustment methodology is included to subtract combined heat and power (CHP) and other onsite power generation. Such an adjustment is of interest to the industrial sector, including fertilizer manufacturers (both phosphate and nitric acid) that generate their own power and often sell it back to the electric grid. The Draft Inventory methodology does not credit industries for carbon-neutral power generation. For phosphate production, the waste heat from sulfuric acid production is recaptured and utilized to generate electricity as a direct off-set to use of other energy sources.

As currently defined, the methodology used in the Draft Inventory may actually result in a doubling of GHGs reported if these phosphate production facilities are not only denied carbon credits for power generation but are also assigned emission shares based on carbon intensity of electrical use.

TFI believes that the Draft Inventory should recognize efforts by manufacturers to utilize "waste" heat that would otherwise be vented to the atmosphere and reduce reported greenhouse gas emissions accordingly. This applies both to the phosphate fertilizer and nitric acid sectors. This beneficial reuse scenario truly represents green energy and should be recognized and encouraged by EPA and, as such, addressed in the Draft Inventory.

If necessary, TFI is willing to solicit information from its members and report the data to EPA.

TFI estimates that member' phosphate facilities, alone, off-set approximately 6.8 to 10 million metric tons of greenhouse gases by capturing waste heat in sulfuric acid production (phosphate) and making electricity.

TFI requests that EPA revise its electricity emissions allocation methodology to reflect the capture and use of carbon-neutral energy to off-set a comparable amount CO_2 allocated either to phosphate and nitric acid production facilities.

Comment: In discussing CO_2 transport, injection, and geological storage (p. 3-55), EPA states that "…all anthropogenic CO_2 emitted from natural gas processing and ammonia plants is assumed to be emitted to the atmosphere, regardless of whether the CO_2 is captured or not.

These emissions are currently included in the Natural Gas Systems and the Ammonia Production sections of the Inventory report, respectively."

TFI appreciates the inclusion of a qualitative description of the IPCC methodological guidance to estimate emissions from the capture, transport, injection, and geological storage of CO2, and that EPA intends to evaluate data from geologic sequestration of CO2 under the Underground Injection Control Program to consider opportunities for improving current inventory estimates (p. 3-54).

However, TFI does not agree with the Agency's refusal to include its estimate of 0.7 Tg CO2 captured from ammonia production sites simply because annual reports for geologic sequestration were not received and "therefore the estimates in the Inventory assume that all injected CO2 (e.g., from EOR operations) is emitted" (p. 3-55). Further, TFI disagrees with the Agency's decision to assume that "naturally-occurring CO2 used in EOR operations is assumed to be fully sequestered," while "all anthropogenic CO2 emitted from natural gas processing and ammonia plants is assumed to be emitted to the atmosphere, regardless of whether the CO2 is captured or not" (3-55).

EPA routinely develops and revises CO2 estimation methods throughout subsequent versions of the Inventory and should therefore use its estimate of CO2 captured at injection sites. Ammonia production facilities routinely capture and sell CO2 for enhanced oil and gas recovery projects. Data on the amount of CO2 used for this purpose are readily available and should be incorporated as offsets for the Ammonia Production sector. In addition, as this practice has been ongoing in the tertiary oil recovery sector for over 30 years. There are a number of peer reviewed publications describing the practice, and demonstrating with monitoring data that very little of the CO2 injected is ultimately released (the CO2 replaces the pore space that the displaced oil resided in).

TFI requests that EPA include its estimate of sequestered CO2 in the Draft Inventory and that EPA revise its methodology for the Ammonia Production sector to credit facilities for CO2 sequestration.

Commenter: Curtis A. Holsclaw

Federal Aviation Administration

Comment: From 2008 to 2009, CO2 emissions from the transportation end-use sector declined 4 percent. The decrease in emissions can largely be attributed to decreased economic activity in 2009 and an associated decline in the demand for transportation. Modes such as medium- and heavy-duty trucks were significantly impacted by the decline in freight transport. From 2009 to

2011, CO_2 emissions from the transportation end-use sector stabilized as economic activity rebounded slightly.

Comment: Suggested revision to table 2-15: Transportation-Related Greenhouse Gas Emissions

Gas/Vehicle	1990		2005		2007	2008	2009	2010	2011
~~Commercial Aircraft [a]~~	~~115.7~~		~~138.0~~		~~145.2~~	~~132.3~~	~~124.3~~	~~117.8~~	~~119.1~~
~~CO2~~	~~114.5~~		~~136.6~~		~~143.8~~	~~131.0~~	~~123.0~~	~~116.6~~	~~117.9~~
Commercial Aircraft [a]	**111.0**		**134.0**		**141.1**	**128.6**	**120.7**	**114.4**	**115.7**
CO2	109.9		132.7		139.7	127.3	119.5	113.3	114.6
CH4	0		0		0	0	0	0	0
N2O	1.1		1.3		1.4	1.3	1.2	1.1	1.1

[a] Consists of emissions from jet fuel consumed by domestic operations of commercial aircraft (no bunkers).

Comment: From 2010 to 2011, CO_2 emissions from the transportation end-use sector decreased by 0.4 percent. The decrease in emissions can largely be attributed to slow growth in economic activity in 2011, decreasing median household income, higher fuel prices and an associated decrease in the demand for passenger transportation. Modes such as medium- and heavy-duty trucks were impacted by the increase in freight transport, driven in part by increases in durable goods manufacturing and international trade, which increased faster than the economy as a whole. In contrast, commercial aircraft emissions continued to fall, having decreased 18 percent since 2007. Decreases in jet fuel emissions (excluding bunkers) are due in part to improved operational efficiency that results in more direct flight routing, improvements in aircraft and engine technologies to reduce fuel burn and emissions, and the accelerated retirement of older, less fuel efficient aircraft.

Comment: CO_2 from the domestic operation of commercial aircraft increased from 1990 to 2011. Across all categories of aviation68, CO_2 emissions decreased by 8.4 percent (13.2 Tg CO_2 Eq.) between 1990 and 2011. This includes a 67 percent (23.0 Tg CO_2 Eq.) decrease in emissions from domestic military operations. For further information on all greenhouse gas emissions from transportation sources, please refer to Annex 3.2.

Comment: Suggested revision to Commercial Aircraft data for table 3-12

Fuel/Vehicle Type	1990		2005		2007	2008	2009	2010	2011
~~Jet Fuel~~	~~155.3~~		~~169.6~~		~~174.4~~	~~163.9~~	~~151.1~~	~~143.1~~	~~143.3~~
Jet Fuel									
~~Commercial Aircraft~~	~~114.5~~		~~136.6~~		~~143.8~~	~~131.0~~	~~123.0~~	~~116.6~~	~~117.9~~
Commercial Aircraft	**109.9**		**132.7**		**139.7**	**127.3**	**119.5**	**113.3**	**114.6**
Military Aircraft	34.4		18.1		16.1	16.3	14.0	12.5	11.4
General Aviation Aircraft	6.4		14.9		14.5	16.6	14.1	14.0	14.0
~~International Bunker Fuels [c]~~	~~67.3~~		~~81.3~~		~~68.1~~	~~66.7~~	~~57.1~~	~~70.9~~	~~69.8~~
International Bunker Fuels from Commercial Aviation	30.0		55.6		57.5	52.4	49.2	57.4	61.7

[c] Official estimates exclude emissions from the combustion of both aviation and marine international bunker fuels; however, estimates including international bunker fuel-related emissions are presented for informational purposes.

Comment: Page 3-21, lined 3-6: Please add the following footnote "The IPCC Tier 3B methodology is used for estimating emissions from commercial aircraft."

The methodology used by the United States for estimating CO2 emissions from fossil fuel combustion is conceptually similar to the approach recommended by the IPCC for countries that intend to develop detailed, sectoral-based emission estimates in line with a Tier 2 method in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006).

Comment: Please revise the above with the following and delete footnote 80. "For jet fuel used by aircraft, CO2 emissions from commercial aircraft were developed by the U.S. Federal Aviation Administration (FAA) using a Tier 3B methodology, consistent with the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (see Annex 3.3). CO2 emissions from other aircraft were calculated directly based on reported consumption of fuel as reported by EIA. Allocation to domestic general aviation was made using FAA Aerospace Forecast data (FAA 2011), and allocation to domestic military uses was made using DoD data (see Annex 3.7)."

Compromise: replace footnote 80 with: "CO2 emissions from commercial aircraft were developed by the U.S. Federal Aviation Administration (FAA) using a Tier 3B methodology; a description of this methodology is presented in Annex 3.3."

Comment: Please revise with the following: "During the development of the current Inventory, commercial jet fuel consumption data for the 1990 through 2011 time series was provided FAA. The revised 2000 through 2009 estimates were developed with the Aviation Environmental Design Tool (AEDT) using radar-informed data, and are considered more accurate. The radar-informed method that was used to estimate emissions for commercial aircraft for all years 2000 through 2011 is not possible for 1990 through 1999 because the radar data set is not available for years prior to 2000. FAA developed OAG schedule-informed inventories modeled with AEDT and great circle trajectories for 1990, 2000 and 2010 to generate the best possible jet fuel burn estimates for the 1990 through 1999 time series. International aviation bunker fuel consumption from 1990 to 2011 for commercial aircraft departing from the United States was calculated in the same manner."

Comment: Please revise Table 3-50: CO2, CH4, and N2O Emissions from International Bunker Fuels with the following:

Gas/Mode	**1990**		**2005**		**2007**	**2008**	**2009**	**2010**	**2011**
CO2	**132.8**		**134.3**		**122.0**	**124.9**	**110.7**	**126.9**	**116.2**
~~Aviation~~	~~67.3~~		~~81.3~~		~~68.1~~	~~66.7~~	~~57.1~~	~~70.9~~	~~69.8~~
Aviation: Commercial	30.0		55.6		57.5	52.4	49.2	57.4	61.7
Aviation: Military									
Marine	65.4		53.0		53.9	58.2	53.6	56.0	46.5
CH4	**0.2**		**0.2**		**0.2**	**0.2**	**0.1**	**0.2**	**0.1**
~~Aviation~~	~~+~~		~~+~~		~~+~~	~~+~~	~~+~~	~~+~~	~~+~~
Aviation: Commercial	0.0		0.0		0.0	0.0	0.0	0.0	0.0

Aviation: Military									
Marine	0.1		0.1		0.1	0.1	0.1	0.1	0.1
N2O	**1.3**		**1.3**		**1.1**	**1.1**	**1.0**	**1.2**	**1.1**
Aviation	0.7		0.8		0.7	0.7	0.6	0.7	0.7
Marine	0.5		0.4		0.4	0.5	0.4	0.4	0.4
~~Total~~	~~134.2~~		~~135.7~~		~~123.2~~	~~126.2~~	~~111.9~~	~~128.2~~	~~117.4~~
Total	**96.9**		**110.0**		**112.6**	**111.9**	**104.0**	**114.7**	**109.3**

Comment: Please revise with the following: "The radar-informed method that was used to estimate emissions for commercial aircraft for all years 2000 through 2011 is not possible for 1990 through 1999 because the radar data set is not available for years prior to 2000. FAA developed OAG schedule-informed inventories modeled with AEDT and great circle trajectories for 1990, 2000 and 2010 to generate the best possible jet fuel burn estimates for the 1990 through 1999 time series.

International aviation bunker fuel consumption from 1990 to 2011 for commercial aircraft departing from the United States was calculated in the same manner as the domestic emissions estimates for commercial aircraft."

Comment: Please revise to reflect Commercial Aircraft data, as follows Table 3-53: Aviation Jet Fuel Consumption for International Transport (Million Gallons).

Nationality	**1990**		**2005**		**2007**	**2008**	**2009**	**2010**	**2011**
~~U.S. and Foreign Carriers~~	~~7,160~~		~~8,518~~		~~7,133~~	~~6,990~~	~~5,981~~	~~7,422~~	~~7,306~~
U.S. and Foreign Carriers	3155		5858		6055	5517	5182	6044	6496
U.S. Military	862		462		410	386	367	367	326
~~Total~~	~~8,021~~		~~8,980~~		~~7,544~~	~~7,376~~	~~6,348~~	~~7,789~~	~~7,632~~
Total	**4017**		**6320**		**6465**	**5903**	**5549**	**6411**	**6822**

Note: Totals may not sum due to independent rounding.

Comment: Page 3-72 lines 25-30. PLEASE DELETE the following since the improvements are incorporated with this submission:

Planned Improvements

The 2011 data formats, developed by the FAA using radar-informed data from the ETMS for 2000 through 2011 as modeled with the AEDT, will be used to produce emission estimates for future inventories and recalculations of prior inventories. This bottom-up approach is in accordance with the Tier 3B method from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories. The activity data covers the time series 1990 through 2011 with domestic defined as the 50 states and separately as the 50 states and U.S. Territories.

Comment: Please revise Commercial Aircraft data:

Annex3, Table A-89. Fuel Consumption by Fuel and Vehicle Type (million gallons unless otherwise specified)

Fuel/Vehicle Type	**1990**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Jet Fuel d	16,171	15,565	15,869	16,152	16,026	17,248	17,848	16,431	15,855	16,031	16,596	17,398	17,784	17,886	16,806	15,501	14,679	14,697
~~Commercial Aircraft~~	~~11,925~~	~~12,510~~	~~12,877~~	~~13,336~~	~~12,990~~	~~14,149~~	~~14,709~~	~~13,154~~	~~12,806~~	~~12,975~~	~~13,180~~	~~14,011~~	~~14,463~~	~~14,745~~	~~13,434~~	~~12,620~~	~~11,961~~	~~12,097~~
Commercial Aircraft	11,568	12,136	12,492	12,937	12,601	13,726	14,672	13,121	12,774	12,942	13,146	13,976	14,426	14,707	13,400	12,588	11,931	12,067

d Estimated based on EIA transportation sector energy estimates by fuel type, with bottom-up activity data used for apportionment to modes

Comment: Please Revise Commercial Aircraft data

Annex3, Table A-90: Energy Consumption by Fuel and Vehicle Type (Tbtu)

Note: Incorrect Footnote Shown for Jet Fuel (it should be "d" rather than "c")

Fuel/Vehicle Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Jet Fuel e **d**	2,183	2,101	2,142	2,181	2,163	2,329	2,409	2,218	2,140	2,164	2,240	2,349	2,401	2,415	2,269	2,093	1,982	1,984
~~Commercial Aircraft~~	~~1,610~~	~~1,689~~	~~1,738~~	~~1,800~~	~~1,754~~	~~1,910~~	~~1,986~~	~~1,776~~	~~1,729~~	~~1,752~~	~~1,779~~	~~1,892~~	~~1,952~~	~~1,991~~	~~1,814~~	~~1,704~~	~~1,615~~	~~1,633~~
Commercial Aircraft	1,562	1,638	1,686	1,747	1,701	1,853	1,981	1,771	1,725	1,747	1,775	1,887	1,948	1,986	1,809	1,699	1,611	1,629

c Fluctuations in recreational boat gasoline estimates reflect the use of this category to reconcile bottom-up values with EIA total gasoline estimates.

d Estimated based on EIA transportation sector energy estimates, with bottom-up data used for apportionment to modes.

Comment: Annex 3 PDF page 24

Please note that the Commercial Aviation component of total jet fuel data has been revised

Table A- 99: Fuel Consumption for Off-Road Sources by Fuel Type (million gallons)

Vehicle Type/Year	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Aircraft a	16,545	15,894	16,180	16,482	16,321	17,574	18,150	16,722	16,136	16,282	16,855	17,693	18,062	18,149	17,042	15,722	14,904	14,922
Aviation Gasoline	374	329	311	330	295	326	302	291	281	251	260	294	278	263	235	221	225	225
Jet Fuel	16,171	15,565	15,869	16,152	16,026	17,248	17,848	16,431	15,855	16,031	16,596	17,398	17,784	17,886	16,806	15,501	14,679	14,697
Commercial Aviation component of jet fuel	11,568	12,136	12,492	12,937	12,601	13,726	14,672	13,121	12,774	12,942	13,146	13,976	14,426	14,707	13,400	12,588	11,931	12,067

a For aircraft, this is aviation gasoline. For all other categories, this is motor gasoline.

Comment: Annex 3 PDF pages 27-28

Please Revise Commercial Aircraft data

Table A- 106: Emission Factors for CH4 and N2O Emissions from Non-Road Mobile Combustion (g/kg fuel)

Vehicle Type/Fuel Type	N2O	CH4
Aircraft		
Jet Fuel	0.10	0
Aviation Gasoline	0.04	2.64

Comment: *Annex3, PDF file page 37*

Please Revise Commercial Aircraft data as follows

Table A-112: Total U.S. Greenhouse Gas Emissions from Transportation and Mobile Sources (Tg CO2 Eq)

Mode / Vehicle																		Percent Change
Type /Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	1990-2011
~~Commercial Aircraft~~	~~115.7~~	~~121.0~~	~~126.8~~	~~131.3~~	~~127.9~~	~~139.4~~	~~144.9~~	~~129.5~~	~~126.1~~	~~127.8~~	~~129.8~~	~~138.0~~	~~142.4~~	~~145.2~~	~~132.3~~	~~124.3~~	~~117.8~~	~~119.1~~	~~3%~~
~~Jet Fuel~~	~~115.7~~	~~121.0~~	~~126.8~~	~~131.3~~	~~127.9~~	~~139.4~~	~~144.9~~	~~129.5~~	~~126.1~~	~~127.8~~	~~129.8~~	~~138.0~~	~~142.4~~	~~145.2~~	~~132.3~~	~~124.3~~	~~117.8~~	~~119.1~~	~~3%~~
Commercial Aircraft	111.0	116.3	119.8	124.1	120.9	131.6	140.7	125.9	122.5	124.1	126.1	134.0	138.4	141.1	128.6	120.7	114.4	115.7	4%
Jet Fuel	111.0	116.3	119.8	124.1	120.9	131.6	140.7	125.9	122.5	124.1	126.1	134.0	138.4	141.1	128.6	120.7	114.4	115.7	4%

Comment: Please Delete The Text at Annex 7 PDF page 10 (lines 15-18) and replace with: "it contradicts U.S. Environmental Protection Agency guidance; namely that "…methane is no longer considered to be an emission from aircraft gas turbine engines burning Jet A at higher power settings and is, in fact, consumed in net at these higher powers." (Recommended Best Practice for Quantifying Speciated Organic Gas Emissions from Aircraft Equipped with Turbofan, Turbojet and Turboprop Engines, EPA-420-R-09-901, May 27, 2009, http://www.epa.gov/otaq/aviation.htm)."

Commenter: Erica Bowman

America's Natural Gas Alliance

Comment: ANGA supports EPA's change to the re-fracture rate used to estimate emissions from unconventional gas wells. In the 2013 Draft Inventory, EPA uses a re-fracture rate of one percent. Previous inventories used a re-fracture rate of 10 percent, which overestimated the actual number of wells being re-fractured. While the one percent re-fracture rate is much closer to actual practices, we believe that it is still an overestimation. A September 2012, API/ANGA study characterizing pivotal sources of methane emissions from natural gas production2 concluded that 0.5 percent was a more representative national re-fracture rate, while our preliminary assessment of the Greenhouse Gas Reporting Program suggests a re-fracture rate of 0.4 percent for wells with hydraulic fracturing.

Comment: In addition, we agree it is appropriate for EPA to revise the estimates of emissions from liquids unloading. Per ANGA's previous comments, the methodology used to estimate emissions from liquids unloading in previous inventories resulted in estimates that were significantly higher than actual emissions.
3 For the 2013 Draft Inventory, EPA incorporated data from an API/ANGA study that better characterizes emissions from liquid unloading.4 These data, which showed wider use of plunger lifts and other control technology than assumed in previous inventories, led EPA to change its emission calculation methodology. As a result of these changes, EPA dramatically reduced its estimate of 2010 emission from liquids unloading from 85.7 million metric tons of carbon dioxide equivalent (mmtCO2e) in the 2012 Inventory to 5.4 mmtCO2e in the 2013 Draft Inventory, a reduction of 94 percent.

Comment: ANGA and its members continue to disagree with EPA's methodologies concerning estimates of emissions from well completions and workovers. EPA's estimate that 9,000 thousand cubic feet (Mcf) of natural gas is released per well completion is fundamentally flawed due to its reliance on data from the Natural Gas STAR program. Under this program, companies voluntarily use reduced emission completions (RECs) to capture gas that would otherwise escape into the atmosphere. As noted in a presentation during the GHG Inventory workshop hosted by EPA in September 2012, when RECs are deployed, a well's flowback process or period is typically 8 to 12 days, compared to an industry average flowback period of 3.5 days for completions without RECs.6 In addition, while there is variation from well to well and play to play, the rate at which gas is produced generally increases over time during the flowback process. The flowback process begins with 100% produced water and no gas. Over time (this could be hours or days) the gas increases and the produced water decreases until the well has sufficient rate and pressure to establish production. This means that the cumulative volume of gas captured over an 8 day flowback period is exponentially greater than that which would be released during 3 days from a non-REC completion at the same well. This reality compounds EPA's overestimate.

Comment: EPA is improperly assigning the emission factor of 9,000 Mcf per completion to a large number of well completions and workovers. The 2013 Draft Inventory underestimates the number of green completions and workovers currently being carried out at wells across the country. In the Draft Inventory, EPA states that it applies a capture rate of 14 percent for well completions and recompletions conducted from 2009 through 2011, based on a review of state regulatory requirements, before accounting for voluntary reductions reported through the Natural Gas STAR program.7 The remaining gas is assumed to be vented to the atmosphere. This methodology ignores the fact that many production companies, including those operating in states without green completion requirements and those that do not participate in or report REC data to Natural Gas STAR, are performing RECs on their own accord for economic reasons. A study by researchers at MIT published in November 2012 and cited by EPA on page 3-62 of the 2013 Draft Inventory found that even with a conservative long-term wellhead gas price of $4 per Mcf and a REC cost of $3,000 per day, 64 percent of wells would generate positive revenue selling gas captured during green completions. Wells profiting from RECs would jump to 83 percent and 95 5 As supplementary material posted for the MIT study notes “regulation is only part of the gas-handling picture.” These findings reinforce the results of a 2011 survey that ANGA submitted to EPA as part of a previous round of comments. That survey found that 93 percent of the roughly 1500 wells reported by survey participants used RECs, four percent flared and only three percent vented gas during the flowback process. A third data source, EPA’s GHGRP, also indicates that the draft inventory overestimates emissions from this source. As stated in the Draft Inventory, “The GHGRP data indicate that the Inventory activity data on well completions and use of RECs compare well with the industry-reported activity data, but that substantial flaring of completion and re-fracturing emissions may be occurring that is not captured in the GHG Inventory (3-63).” The information in these three independent works provides EPA with information of sufficient quality to construct a time series representation of the significant gas capture that occurs in addition to what is depicted by regulations and Natural Gas STAR reports.

Comment: At an absolute minimum, EPA should include a statement at the beginning of Chapter 3 of the inventory, and in a footnote to every table and figure that includes emissions from Natural Gas Systems, to the effect: The Agency is in the process of revising its methodologies. Until such time as the methodologies have been revised and implemented and new emissions estimates are available, the emissions estimates presented herein should not be relied upon or otherwise used as the basis for any analysis or regulatory action.

Commenter: Ursula Rick

Western Energy Alliance

Comment: EPA relies on its technical analysis for the recent NSPS/NESHAP Rule for Oil and Gas1 to estimate methane emissions from hydraulic fracturing and refracturing. In our comments on that rule, we show that EPA grossly overestimates methane emissions in its analysis2 due to poor assumptions, such as the amount of venting versus flaring, use of reduced emissions completions (REC) only where required by regulations, and composition of flowback material.

An IHS CERA report, Mismeasuring Methane: Estimating Greenhouse Gas Emissions from Upstream Natural Gas Development explains how EPA overestimated methane emissions3 and calculates a very conservative estimate of 43 million tons CO2e methane emitted from natural gas field production in 2009. EPA's estimate for natural gas field production was 130 million tons CO2e for 2009, more than three times greater. We are troubled that EPA continues to rely on its NSPS/NESHAP Oil and Gas Rule analysis for the Inventory, especially when new data has become available from both academic and government sources.

More recent analysis by O'Sullivan and Paltsev4 of MIT has shown much fewer potential methane emissions from hydraulic fracturing using more realistic industry practices than are assumed in EPA's technical analysis1. They found the 2010 potential fugitive methane emissions from hydraulic fracturing to be 902 Gg methane from 3948 wells throughout 5 plays (Barnett, Fayetteville, Haynesville Marcellus and Woodford). In comparison, the EPA 2012 GHG inventory for upstream fugitive methane emissions estimates the 2010 value at 6002 Gg methane using far fewer data points. Keep in mind these are potential emissions, not actual emissions, and do not take into account reductions from REC and other controls.

Results from the EPA's own Greenhouse Gas Reporting Program (GHGRP)5 also show fewer emissions from hydraulic fracturing and refracturing than the Inventory. The GHGRP data show methane emissions of 6.1 Tg CO2e while the Inventory estimates emissions of 15.3 Tg CO2e. We recognize the GHGRP data covers only those sources with emissions greater than 25,000 tons/year and therefore will miss some emissions, but we do not believe it is missing over 60% of the emissions from hydraulic fracturing and refracturing. EPA itself claims the GHGRP data covers approximately 85-90% of GHG emissions in the US6. EPA has taken into account GHGRP data in estimating emissions from other parts of the natural gas sector for the Inventory but not hydraulic fracturing and refracturing. We encourage EPA to investigate this discrepancy between the Inventory assumptions and the GHG emissions data reported by industry to improve its methane emissions numbers.

Western Energy Alliance does support EPA's revision of the refracture rate. Previous inventories had used a refracture rate of 10%, but that has been reduced to 1% for the Inventory. This reflects industry practice more accurately and produces more accurate methane emissions estimates from refracturing of wells.

Finally, Western Energy Alliance supports EPA's adjustments to the assumptions for liquids unloading emissions for the Inventory by incorporating data from an API/ANGA study7. The study shows greater use of control technology than assumed in previous inventories, and EPA reduced its estimate of 2010 emission from liquids unloading from 85.7 Tg CO2e in the 2012 Inventory to 5.4 Tg CO2e in the 2013 Draft Inventory.

It is important that EPA's emissions estimates for the natural gas sector are as accurate as possible in the Inventory, and EPA has a new source of data directly from industry in the GHGRP. The large discrepancy between the Inventory methane emissions and the GHGRP methane emissions reported by industry should be examined carefully to understand where Inventory assumptions might be incorrect. Methane emissions from the natural gas sector continue to be extensively studied by industry and in the academic literature, and we encourage EPA to make use of that information when making the necessary assumptions to calculate US emissions from natural gas.

Commenter: Pamela Lacey

American Gas Association

Comment: AGA applauds EPA's decision to improve the accuracy of the Draft Inventory this year by incorporating new, robust methane emissions data on natural gas production well liquids unloading and the frequency of well refracturing. As a result, the Draft Inventory now estimates the methane emissions rate for the natural gas value chain, from production well to consumer, as 1.35% of produced gas.1 We believe this is getting closer to reality than the highly inflated estimate in last year's Inventory and should help to provide a more rational basis for energy and environmental policy.

Comment: For example, comments filed by America's Natural Gas Alliance (ANGA) and the American Petroleum Institute (API) note that EPA still has not changed the methodologies for estimating the quantity of methane emitted from well completions and workovers (apart from reducing the assumed frequency of refracturing), despite robust data provided by ANGA and API from a 2012 survey of 2011 production practices and emissions conducted by URS and The LEVON Group. AGA agrees that EPA should correct this deficiency before issuing the final 2013 Inventory. Failing to do so continues to inject an inflated assumed methane emissions rate into an important public policy debate on energy choices.

Comment: We further urge EPA to note that despite improvements, the 2013 Inventory may still overstate emissions and that additional data will be available for incorporation in the next Inventory that is expected to demonstrate that the annual emissions rate is even lower.

For example, EPA has now validated data submitted in September 2012 under the "Subpart W" mandatory greenhouse gas reporting rule that demonstrates lower emissions rates from a variety of natural gas operations. While this data was not validated in time to be incorporated in the 2013 Inventory, it will certainly be available for inclusion next year.

The Subpart W data for 2012 emissions will be reported by the end of March 2013, allowing ample time to validate the data and include it in the 2014 Inventory. The 2012 emissions data can be expected to reflect a continuing downward trend due to the expanded use of practices such as green well completions and the replacement of older cast iron and unprotected steel distribution pipe with modern plastic pipe.

Comment: As more emission factors are developed based on actual field tested emissions, EPA will also need to reflect this change in its methodology as appropriate, which is currently designed to use the 20-year old GRI emission factors to estimate potential emissions, and then to subtract emission reductions due to regulatory and voluntary actions in an attempt to estimate lower actual emissions.

Comment: An innovation in the 2013 Inventory is to describe this methodology more clearly than in past Inventories. AGA very much appreciates this transparent approach, as it should help reduce the public's confusion and the opportunities for spreading serious misinformation about what the Inventory actually says about the carbon footprint of the natural gas value chain.

Commenter: Karin Ritter

American Petroleum Institute

Comment: API supports the changes made to the 2011 national GHG inventory including the advances made in updating the national emission estimation methodology. When accounting for these changes, resulting emissions from Natural Gas Systems are estimated to be 1.5%1 of natural gas withdrawals2. API encourages EPA to state this clearly early in the discussion on Natural Gas Systems to enhance understanding of the data by potential users.

Comment: API appreciates that EPA has added detail and notations for this source and other emission sources in the petroleum and natural gas sectors to differentiate between potential emissions and emissions after accounting for reduction activities. API encourages EPA to continue to emphasize these differences for each.

Comment: API has previously expressed concerns that the emission factor applied to gas well completions and workovers with hydraulic fracturing overstates emissions for these operations. The average emission factors used in the 2011 national GHG inventory are: 9,000 Mscf of potential natural gas emissions; or 3,841 Mscf of natural gas emissions per event after accounting for emission reduction activities. Review of data reported through the GHGRP and presented by EPA in the February 27, 2013 webinar results in emission factors of 2,244 Mscf of natural gas/event for completions with hydraulic fracturing and 962 Mscf gas/event for workovers with hydraulic fracturing. The GHGRP emission factors are based on approximately 200 basin-wide reporting facilities, representing 9,800 completions and 1,300 workovers. This is a much broader data set than the information used to develop the emission factor currently used in the national inventory. This should be noted by EPA as an area of enhancements in future inventories.

Comment: On Page 3-63 of the inventory report, EPA compares initial GHGRP data for gas well completions and refracturing (i.e., workovers) with hydraulic fracturing, totaling 6.1 Tg CO2e of CH4, to the 2011 national inventory emissions of 15.3 Tg CO2e of CH4. EPA indicates that a lower GHGRP result is expected since the GHGRP excludes facilities below the reporting threshold (EPA has publicly stated that the GHGRP accounts for 85-90% of total GHGs emitted). Although we agree that the GHGRP data does not capture all facilities, this exclusion of facilities below the reporting threshold does not account for a difference of 9.2 Tg CO2e, or about a 60% difference in emissions.

Comment: API also recognizes that the initial GHGRP data include emission estimates utilizing Best Available Monitoring Methods (BAMM), particularly in this first year of reporting. Although further review and analysis is needed of the GHGRP information and use of BAMM, API encourages EPA to consider the broader data set available through the GHGRP in future updates to the national GHG inventory.

Comment: EPA states (page 3-63) that initial GHGRP data analysis shows higher CH4 emissions from liquids unloading than calculated in the revised 2011 GHG inventory: 5.2 million metric tonnes (MMT) CO2e of CH4 from the 2011 national inventory, compared to 6.5 MMT CO2e of CH4 reported through the GHGRP. The higher emissions from the GHGRP seem to be driven by data reported from one facility in the San Juan Basin. Excluding this one source, the emissions reported through the GHGRP are lower than emissions in the draft 2011 national inventory. This example is indicative of the need for further investigation of the data reported to the GHGRP to understand emissions from liquids unloading.

Comment: API appreciates that EPA has incorporated findings from the API/ANGA study for this emission source. The API/ANGA study, which represented 2010 and partial 2011 data, resulted in 65,669 wells venting for liquids unloading when extrapolated across the U.S. This compares reasonably well with EPA's estimate of 58,694 wells venting for liquids unloading for 2011. However, the API/ANGA report indicated more wells with plunger lifts vented for liquids unloading (36,806 wells of the 65,669 total wells), while the EPA inventory reports a higher number of wells venting for liquids unloading without plunger lifts than with plunger lifts. Data reported through the GHGRP seems to be more consistent with the API/ANGA data, resulting in 42,728 wells venting for liquids unloading with plunger lifts and 26,567 wells venting for liquids unloading without plunger lifts.

Comment: EPA's regional application of the API/ANGA data appears to be skewing the extrapolated counts of wells with and without plunger lifts, and results in widely varying emission factors by region as shown in Table 1. EPA should note this as an area for improvement. Data reported through the GHGRP will provide a broader coverage of U.S. natural gas operations than the API/ANGA study and a better understanding of the regional distribution of liquids unloading with and without plunger lifts. Table 1 lists the regional breakdown of emission factors calculated by EPA for liquids unloading with and without plunger lifts. It also compares average national emission factors for the 2011 national inventory to the emission factors derived from the API/ANGA study.

Table 1. Comparison of Liquids Unloading Emission Factors

	Liquids Unloading with plunger lifts	**Liquids Unloading without plunger lifts**
2011 National GHG Inventory	**CH_4 Emission Factor (scfy CH_4/well)**	**CH_4 Emission Factor (scfy CH_4/well)**
North East	254,851	134,603
Midcontinent	1,177,705	196,460
Rocky Mountain	119,840	2,003,373
Southwest	2,856	77,900
West Coast	317,292	279,351
Gulf Coast	62,035	266,308
National Inventory Average	**246,215**	**215,209**
API/ANGA Study	**272,130**	**239,590**

Comment: While considering the very large GHGRP dataset for future inclusion, it should be noted that facilities have included use of best available monitoring methods (BAMM) in 2011 reporting and may continue to use BAMM in the future. For example, 167 basin-wide facilities reporting emissions data for liquids unloading utilized BAMM, out of 448 total basin-wide onshore oil and gas production facilities reporting to the GHGRP. The use of BAMM in the GHGRP needs to be evaluated as part of the process for considering the GHGRP data to improve the national GHG inventory.

Comment: Well counts: In the Expert Review draft of the inventory, API commented on the significant changes to well counts and activity data from 2010 to 2011. EPA explains that these changes result from EPA switching to DI Desktop as the source of the well information (page 3-

64). However, the large change in well counts from 2010 to 2011 (679,671 total gas wells in 2010 compared to 425,974 gas wells in 2011) and the discrepancy between EPA's count of wells and well counts published by EIA (514,637 gas wells for 20114) raises concerns with the database query used for the 2011 national inventory. The inventory document does not describe the criteria EPA uses to classify wells. API believes there are still outstanding issues related to the well counts for the national inventory that need further follow-up.

Comment: Well definitions: EPA has revised the definition for non-associated gas wells, and describes gas wells with hydraulic fracturing as a subset of non-associated gas wells (page A-173). API supports these revisions.

Comment: In reevaluating EPA's count of wells drilled from DI Desktop, the count 14,869 wells drilled appears correct.

Comment: Gas Well Completions: The national inventory reports a total of 8,875 gas well completions for 2011 (8,077 completions with hydraulic fracturing and 798 completions without hydraulic fracturing from Table A-124). In practice, there are occasional dry holes drilled that are not completed. Nonetheless, the difference between the number of wells drilled (14,869) and the number of wells completed (8,077) is much larger than the number of dry holes that would be expected in a given year. API believes the count of gas well completions is underestimated.

Comment: Gas Well Workovers: API commented in the Expert review that the number of workovers with and without hydraulic fracturing decreased significantly from 2010 to 2011. The inventory documentation does not address the source of information for the count of workovers and does not discuss the change from 2010 to 2011 (26,132 in 2010 compared to 13,449 in 2011). The national inventory count of workovers with hydraulic fracturing for 2011 (1,786 workovers) is only slightly higher than the number of workovers identified in the API/ANGA report (1,461 workovers with hydraulic fracturing), where the API/ANGA survey only captured data from a subset of the U.S. natural gas producers. Data reported to the GHGRP shows 1,329 workovers with hydraulic fracturing, and also may not have captured all U.S. natural gas producers due to the defined facility reporting threshold. For transparency, API suggests adding details on how the number of workovers is determined for the national inventory.

Comment: The Public Review version of the national inventory replaced the term "re-completions" with "refracturing" to describe workovers. For consistency with reporting to the GHGRP, API suggests maintaining the terminology of "workovers with hydraulic fracturing", and including the new terminology "refracturing" in parentheses.

Comment: API reiterates its suggestion from previous comments that a table (or tables) be added to Annex A to document the CH4 composition data that are used for both the Natural Gas Systems and Petroleum Systems. This would be similar to the new Tables A-13 through A-17 that provide CO2 composition information. API also notes that the table numbers for the CO2 compositions are out of sequence with other tables in Annex A.

Comment: The emissions from associated gas included in the Petroleum Systems. Currently, these emissions are listed under "Tank Venting" in Section 3.6 of the main inventory report and under "Oil Tanks" in Section 3.6 of Annex A. For improved clarity and transparency, API suggests including "associated gas emissions" in parentheses where emissions from these sources are presented. For future inventories, Petroleum Systems should include an emission source category for "associated gas venting and flaring" emissions to align with the GHGRP.

Comment: Page 3-65 indicates that GasSTAR data was recalculated and resulted in a change in the emission reductions from 55.8 Tg CO2e for 2010 in the previous Inventory to 57.4 Tg CO2e for 2010 in the current Inventory. The inventory documentation notes that this is a small decrease in the GasSTAR reductions. However, the numbers cited actually indicate a slight increase in the reductions for 2010.

Comment: On page 3-67, EPA acknowledges receiving the El Paso data on centrifugal compressor emissions for wet and dry seals. EPA indicates that they will review this information for future Inventory revisions. API supports the review of industry information for potential updates to the national inventory.

Commenter: David McCabe

Clean Air Task Force

Comment: *As we commented in 2013, we note significant flaws in the API / ANGA survey the EPA has used as the basis for the new emissions factors for Liquids Unloading (LU). We do not believe EPA's decision to remove from consideration the previous data for LU emissions (that used to estimate LU emissions in the 2011 and 2012 Inventories) is justified.*

In light of the limited data for LU emissions, we suggest that EPA examine the GHGRP data for illumination of the drivers of LU emissions, including some specific suggestions.

Finally, we suggest that EPA acknowledge the reports in the literature of measurements of elevated concentrations of methane and other hydrocarbons in ambient air near gas production sites. These reports have been analyzed, with results that indicate that for some gas production regions, emissions of methane are substantially higher than reported in the Draft 2011 Inventory, or previous editions of the Inventory. While the difference between the results calculated from ambient measurements and the Inventories is not well understood, and controversial, acknowledging the difference is critical so that readers can put the Inventory's results in the proper context.

Commenter: Cynthia Finley
National Association of Clean Water Agencies

Comment: The Executive Summary of the Inventory should caution potential users that the Inventory's stated purpose is for information, not regulation. EPA should ensure that all of its offices understand the purpose of the Inventory and recognize that the Inventory's industry-wide methodologies are largely inadequate for facility level emissions, such as those required by EPA's Greenhouse Gas Reporting Rule and the Clean Air Act Title V and Prevention of Significant Deterioration (PSD) permitting programs.

Comment: NACWA encourages EPA to carry out its planned improvements to further refine the accuracy of emissions estimates. As EPA evaluates new research for use in the Inventory estimates, however, we urge caution in using results from studies that were not designed to produce nationally-applicable results. Relying on studies that are not representative of utilities nationwide may actually increase the uncertainty of the estimates.

Comment: NACWA believes the nitrogen loading rates for N2OEFFLUENT are sourced incorrectly and that using information from the existing National Pollutant Discharge Elimination System (NPDES) database will yield more accurate and justifiable loading rates. The NPDES permitting program represents longterm, nationwide facility performance which would allow emissions estimate projections over the time series represented in the Inventory.

Comment: If EPA decides not to investigate its own databases, the average nitrogen loading rate of 15.1 g N/capitaday1 represents the industry standard and is supported by a wealth of data widely confirmed in U.S. practice, as explained in our previous comments and supported by data collected by NACWA from 48 U.S. POTWs. This loading rate represents all domestic sources of nitrogen, the use of other nitrogen containing compounds, and both residential and commercial sources.

Comment: NACWA asks that all values used in the equations to calculate emissions be provided in the factor definitions or in the text to enable the calculations to be easily reproduced. For example, the value for USPOPND is not provided – it is only referenced to the Clean Watershed Needs Survey (CWNS). EPA should provide the value that it used from the CWNS.

Comment: Finally, EPA states in the Planned Improvements section that the CWNS data for 2008 were not incorporated due to significant changes in format of the database, and that "additional information and other data continue to be evaluated to update future years of the Inventory." Since the 2004 CWNS data is likely outdated, these additional data sources need to be identified and evaluated soon to ensure the accuracy of future Inventories.

Commenter: Tim A. Pohle

Airlines for America

Comment: Most importantly, the transparency of the evaluation of the commercial aviation sector needs to be greatly improved. For commercial aviation data, the inventory and corresponding Annex 3 list the databases from which the data was derived, but do not clearly explain many of the underlying assumptions or methodologies used to perform analysis. As a specific example, in the Draft GHG Inventory the asserted value for GHG emissions in 1990 from domestic commercial aviation operations is 115.7 Tg CO2 (eq) (see Table A-112); however, last year's inventory stated the same emissions for the same year as 136.8 Tg CO2 (eq) (see Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010, Table A-111). Despite this very significant change, the Draft GHG Inventory does not even note the change or offer any specific explanation justifying the change.

Comment: While the change in modeled emissions estimate for 1990 in this year's draft inventory is most apparent, a brief comparison of past SAGE estimates to AEDT values provided in this year's inventory indicates the shift to AEDT has resulted in significant changes in emissions estimates for recent years as well. EPA does not provide any explanation for its reliance on modeled emissions in favor of actual data reported by airlines through BTS. Also, it is unclear why, given AEDT incorporates SAGE, the results in this year's inventory would vary so greatly from past inventories.

Comment: Given the large changes resulting from the revised modeling of emissions we are very concerned about EPA's reliance on modeled data rather than directly reported data and about the possibility that, with future revisions, the baseline data for commercial aviation in 1990 (and the values for other years) could shift significantly again in the future. The concern is heightened by indication on page A-162 of Annex 3 that a new method for estimating emissions (using "OAG schedule-informed inventories modeled with AEDT and great circle trajectories") may be used to develop new figures for 1990, 2000 and 2010 in the future.3 At the very least, EPA needs to (1) identify the specific calculations it made to estimate commercial aviation emissions in 1990-1999 for the Draft GHG Inventory, (2) identify the specific calculations it made to estimate commercial aviation emissions in 1990-1999 for previous inventories, and (3) explain its reasons for relying on modeled data rather than reported data from the aviation industry.

Comment: With regard to EPA's increased reliance on AEDT for deriving commercial aviation's emissions values in its GHG inventory, we are concerned about the consistency of the definitions of terms used. Specifically, AEDT apparently involves using a different definition of "commercial aviation" than has been previously used in the inventory. While not entirely transparent itself, AEDT may involve analysis under commercial aviation that includes general aviation flights. This would overstate commercial aviation's level of emissions and understate general aviation's level of emissions. The definitions of the subcategories of aviation should be revised as appropriate and fully transparent information should be included in the inventory and appropriate annex. These issues call into question the decision to rely on models to estimate emissions rather than directly reported data, particularly because many policy makers rely on the GHG Inventory.

Comment: A4A has similar concerns regarding the methodologies used to allocate emissions between passenger and cargo carriers and between domestic and international operations. With respect to the former, although EPA relies on modeled data rather than BTS data to estimate overall emissions from the commercial aviation sector, it appears to rely on BTS data to allocate emissions between cargo and passenger carriers. See Annex 3, p. A-158. With respect to the latter, EPA apparently uses Energy Information Administration (EIA) data to determine overall emissions associated with jet fuel and simply subtracts the emissions value derived for domestic aviation sources using FAA models to determine emissions attributable to international aviation. There appears to be no attempt to determine whether the modeled fuel burn matches EIA reported fuel burn and thus whether this methodology is appropriate. Again, the Draft GHG Inventory does not provide sufficient explanation of these methodologies or the reasons reliance on the methodologies is justified.

Commenter: Gretchen Kern

Pioneer Natural Resources

Comment: However, Pioneer would like to emphasize one caveat in regard to the use of GHGRP data for liquids unloading in the application of the EPA methodology. The GHGRP data may tend to overstate emissions because of fundamental assumptions included in the Subpart W mandated formula. For example, the assumption that a full wellbore volume of gas is vented with each unloading would often result in an overestimate of emissions vented. Also, the assumption of an hour of full venting to the atmosphere at normal production rates is not consistent with field operations where the entire reason for unloading the well is to produce gas volumes for sales as soon as the liquid load is removed from the wellbore.

Comment: Additionally, one improvement Pioneer recommends is for EPA to revisit its assumption in the liquid unloading calculation that no plunger lifts or artificial lifts were in operation in any region in 1990. In actuality, these technologies were widely used to remove liquids from the well bore prior to 1990. EPA stated this misassumption in their methodology several times in the 2013 Draft Inventory and further stated that this estimate was increased linearly up to the percentage indicated by the API/ANGA data for that region in 2010. From an industry perspective, a linear increase is not the correct method to illustrate the percentage of use of these technologies. A more logical approach would be a step-wise increase primarily associated with the average price of natural gas.

Comment: In regard to the methodology employed to estimate emissions for Chapter 3.7, Natural Gas Systems, EPA states, "For the inventory, the calculated potential emissions are adjusted using data on reductions reported to Gas STAR, and data on regulations that result in CH4 reductions." It is not sufficient that EPA utilized results from the Natural Gas STAR Program as one of only two methods to account for reductions to EPA's calculated potential emissions. Not all natural gas producers are Natural Gas STAR partners and not all Natural Gas STAR partners report all emission reduction activities. Pioneer, for example, is only a Gas STAR partner for its processing segment, not production, so currently does not report RECs to Gas STAR. Employing technologies for economic reasons (e.g. to capture and sell more gas that would otherwise be emitted), as opposed to solely for emissions control, may not be reported to a voluntary emissions reduction program such as the Natural Gas STAR program. Furthermore, the approach of using the Gas STAR data in this manner is a misapplication of the Gas STAR information.

Comment: First, Pioneer agrees with the use of Drillinglnfo. 2012 to update the well completion numbers and urges EPA to continue to utilize the most robust data and information available.

Comment: Second, regarding EPA's 1% refracture rate reduction from 10% in the 2013 Draft Inventory, Pioneer agrees that this is an important step toward reflecting actual industry practice. However, Pioneers own refracture rate is less than 1% of total hydraulically fractured wells. Therefore, Pioneer questions if EPA's 1% is still an overstatement.

Comment: Third, EPA's potential emission factor for these activities was updated to 9,000 Mscf gas("' 7,477Mscf CH4) per well completion/workover event in 2011. As cited by EPA in the Final NSPS Background Supplemental Technical Support Document (section 1.1.3, page 1-5), Pioneer understands that EPA's completion/workover emission factor represents natural gas produced during the flowback of the completion/workover of a hydraulically fractured natural gas well (i.e., "potential gas emissions from the completion process in the absence of controls to capture or flare the released gas"). In comparison, Pioneer's average potential methane emissions per completion/workover were 9,782 Mscf in 2011.

However, based on Pioneer's final 2011 Subpart W data submittal, Pioneer's total actual vented methane emissions per completion/workover averaged 331 Mscf for its 261 completions/workovers. Therefore, Pioneer vented only 3.4% of its potential methane emissions from completions and workovers, as compared to EPA's estimate of 49% of potential methane emissions actually being vented to the atmosphere (i.e., not captured and/or flared}. Specifically, Pioneer's actual vented methane emissions per completion/workover event varied by basin, depending on formation type. Pioneer calculated 2,190 Mscf/event in a high permeability gas formation, 574 Mscf/event in two shale gas formations, and 8 Mscf/event for a coal seam formation. Further, Pioneer believes its practices are more reflective of industry operations than EPA's assumptions. Overall, generally-speaking the most common industry practice is to install a separator on the well and flare the gas if a sales line is not already available for the completion (with an unavoidable brief period at the beginning of the completion flowback when there is insufficient gas flowing from the well to allow the separator to be function). As a result, Pioneer feels that this source category may require further investigation and industry collaboration to achieve greater consistency between EPA and industry's calculated emission factors.

Comment: Elaborating on this concept of potential v. actual emissions, in the QA/QC and Verification Discussion of Chapter 3.7, Natural Gas Systems, EPA states that "information from O'Sullivan and Paltsev (2012) was reviewed which generally supports EPA's potential emission factor as a national average reflecting potential emissions from all unconventional formation types." The 2013 draft Inventory refers to O'Sullivan and Paltsev's paper to support their potential emission factor but does not provide information from this same source that differs from EPA's conclusions of actual emissions. Namely, O'Sullivan and Paltsev (2012) authors of the MIT study "Shale gas production: potential versus actual greenhouse gas emissions". The MIT study, as discussed in this O'Sullivan and Paltsev's paper, contends that use of flaring and RECs reduce the levels of actual fugitive emissions from shale completion operations from a potential 228 Mg CH4 (11,891 Mscf) per completion to 50 Mg CH4 (2,608 Mscf) per completion based on a 15% vent rate. Although this number was based on a "synthetic scenario designed to reflect a practically achievable mix of gas handling practices for well completions in the main shale plays", it is another point of reference worth noting. EPA's estimate of 49% of potential methane emission being vented to the atmosphere is substantially greater than Pioneers 3.4% and O'Sullivan and Paltsev's 15%. Pioneer appreciates EPA's mention of this paper and suggested intention to review it in detail regarding emissions from shale gas related to planned improvements, however Pioneer urges EPA to reassess their actual completions and workovers with hydraulic fracturing emissions figure in this Draft Inventory to coincide with industry practice and other research.

Comment: An additional problem with EPA's current approach is that it fails to properly take into account the material influence that the varying potentials to emit have on the utilization of natural gas flaring and capture practices during the completion flowback process. For example, many of the wells that do not have flaring or capture of gas during the initial completion flowback period are typically those wells with much lower potentials to emit. This important consideration will have a direct and significant impact on the estimated net emissions. A more accurate approach would be to have a different average potential to emit for the wells that do not have flaring or sales equipment in place during the flowback stage.

The current assumption that wells that do not have flaring or sales equipment in place during the flowback stage have the same high potential to emit as wells that do have such flare or capture for sales equipment in place results in a significant overestimation of emissions during completion events. These wells either produce low rates of natural gas or the f10wback lasts a much shorter time period than those equipped with a separator and either a flare system or a connection to a gathering line. Another vital consideration that the EPA does not appear to acknowledge is that the rate of gas production during a completion flowback is normally very low during the first half of the flow back period and does not reach the full production potential until the very last part of the flowback. To Pioneers knowledge, the most accurate information available at this time is the 2011 ANGA survey that indicated 93% of the completions used REC during the flowback period. Furthermore, many completions have the natural gas separated from the f10wback liquids and the gas is sent directly to a sales line once the fluids being recovered from the well have sufficient gas present to enable the operation of a separator to allow the gas to be put into the sales line.

Comment: Also, for workovers with hydraulic fracturing, the assumption should be that a very high percentage of the potential gas is controlled because separators and gas gathering systems are already in place.

Comment: On a related note, Pioneer requests further explanation of the lower bound uncertainty range in Table 3-48: Tier 2 Quantitative Uncertainty Estimates for CH4 and Non-energy C02 Emissions from Natural Gas Systems (Tg C02 Eq. and Percent). This narrow lower bound is questionable, especially given the fact that the 2013 Draft Inventory initial completion and workovers with hydraulic fracturing emissions are 2.5 times greater than the 2011 estimates reported in the GHGRP.

Comment: In the QAQC and Verification Discussion, EPA states "A result of the lower GHGRP result is to be expected, as GHGRP data excludes well completions occurring at facilities below the GHG reporting threshold of 25,000 Tg C02 Eq. The GHGRP data indicate that the Inventory activity data on well completions and use of RECs compare well with industry-reported activity data, but that substantial flaring of completion and refracturing emissions may be occurring that is not captured in the GHG Inventory." Pioneer requests further clarification of this statement. What is EPA's assumption of the percentage of completions that would not be reported in the GHGRP? There were a total of 9,811 new gas well completions reported under Subpart W in 2011 industrywide per EPA's February 2013 GHGRP Summary; of the total number of gas well completions with hydraulic fracturing from the drilling info database utilized for this Inventory, what percentage of these wells would not have been reported in the GHGRP? Because Subpart W is based on a basinwide aggregate, Pioneer would expect that very few wells in this source category are exempt from reporting. Further and most importantly, does this mean that the Inventory assumes that the gas is being vented, but the GHGRP reports it as being flared? If this interpretation is correct, Pioneer urgently requests that the Inventory data be revised to concur with GHGRP Subpart W data to recognize the controls being utilized for this source category.

Comment: Lastly, EPA states, liAs in previous Inventories, voluntary reductions reported to Gas STAR are also deducted from potential emissions totals." It is not sufficient that EPA utilized only results from the Natural Gas STAR Program to account for reduced emissions completions ("RECs") since not all natural gas producers are Natural Gas STAR partners and not all Natural Gas STAR partners report all emission reduction activities. Pioneer, for example, is only a Gas STAR partner for its processing segment, not production, so currently does not report RECs to Gas STAR. Employing reduced emission completion technologies during the completion process to capture and sell gas that would otherwise be emitted, as opposed to solely for emissions control, may not be reported to a voluntary emissions reduction program such as the Natural Gas STAR program. In fact, reducing flowback emissions and routing these emissions to a sales line is very likely underreported even among Natural Gas STAR partners as it is often regarded as economic recovery as opposed to an emissions reduction activity. The omission of emissions reductions from the application of these commonly utilized, yet underreported activities results in a worst-case scenario approach that is not appropriate for an emissions inventory, and overestimates the emissions from natural gas production. Furthermore, the approach of using the Gas STAR data in this manner is a miss application of the Gas STAR information.

Comment: First, in Chapter 3.6, Petroleum Systems, EPA states "emissions from chemical injection pumps are due to the 25 percent of such pumps that use associated gas to drive pneumatic pumps." How did EPA estimate the number of pneumatic chemical injection pumps, and what methodology was used to assume that 25% of these use associated gas? These types of gas-powered pneumatics are sparsely used at Pioneer; in contrast Pioneer uses mainly solar-powered chemical injection pumps. Has EPA surveyed other operators to understand the prevalence of these types of pneumatics? Or has the EPA used the GHGRP data to estimate this? Pioneer requests that the final draft provide more detailed information on the methodology used to calculate and apply this estimate.

Commenter: Jesse Sandlin

Devon Energy

Comment: The Completions with Hydraulic Fracturing emission factor remains to be an overestimate and an inappropriate use of Natural Gas Star data, and EPA failed to incorporate a method of correctly using the data.

Comment: The draft inventory does not account for the flaring of gas wells where flaring is not required by state regulations, and therefore text in the inventory is incorrect and misleading. EPA ignored Devon's method for determining flaring based on actual well information.

Comment: Devon Energy urges EPA staff to adopt the scientific data and methodology provided to them during the expert review period.

Comment: "In the past years, the inventory has been used to support irresponsible policy arguments and decisions- the inventory has been used for erroneous calculations in scientific journal papers that claim natural gas is no better than coal for its climate change effect…"

Comment: "Devon recognizes the significant progress that has been made between this draft inventory and least year's published version...."

Comment: "Devon also noted the addition of footnote "aa" under Table A-1 and fully supports that caveat. EPA may consider directly highlighting the caution of that footnote by also including the text in the main body of the report."

Comment: "Devon supports the Environmental Protection Agency's effort toward ever-improving environmental quality standards, and believes and accurate representation of actual emissions is important evidence that supports the continued use of natural gas and oil to fulfill much of the nation's energy needs."

Comment: The EPA assumes that 9,000 Mscf of natural gas is emitted from most unconventional well completions. Devon questions the credibility of this emission factor. If true, it would mean that Devon would be losing more than $40 million per year to the atmosphere. Given this estimated forfeiture of significant income, Devon conducted investigations into the industry practices surrounding this estimate and the source of data for the initial estimate. Through this investigation, Devon found the emissions estimate was derived using a flawed methodology, in which data EPA received from the Natural Gas Star program was used appropriately. Problems with the methodology have previously been described in a recent IHS CERA report (Attachment B), in a position paper developed by Devon (Attachment C), in testimony provided by Devon (Attachment D) before the Senate EPW Subcommittee on clean air and Nuclear Safety, in testimony provided by Devon (Attachment G) in Edmond, OK on July 13, 2012, in a presentation presented by Devon (Attachment E) and a paper presented by Dr. Russel Evans and Dr. Jacob Dearmon from Oklahoma City University (Attachment H) at the Greenhouse Gas Inventory Workshop help on September 13-14, 2012, in Washington, DC. Unfortunately, even after these flaws were described and identified, the methodology was not significantly improved upon in the last year. The following are significant findings of those previous documents:

1. The EPA assumes that the volume of gas captured from performing a reduced emissions completion is the same volume of gas emitted when reduced emissions completions are not performed. This assumption is invalid. IHS CERA states "EPA derives its new 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."

2. It is unknown how the Natural Gas Star data was calculated. It is not known whether consistent methods were used or how robust the data is. Green completion or reduced emission completion reporting under the Natural Gas Star Program was never meant to represent emissions from wells that were not green completed. The quality of this data and what it represents is questionable.

3. EPA assumes that producers vent to the atmosphere during flowback, rather than commonly flaring or capturing emissions, in those states that do not mandate flaring or recovery. This assumption is flawed and is further evaluated in the second section below.

4. EPA assumes that flowback periods for wells that use reduced emissions completion equipment are identical to those periods for wells that are vented or flared. However the URS Memo Data (Attachment A) provided below shows this assumption to be incorrect. From the survey data, for the wells that were completed using reduced emissions completion equipment, the average flowback duration was 7.7 days. For those wells whose emissions were flared or vented instead this average value was only 3.5 days.

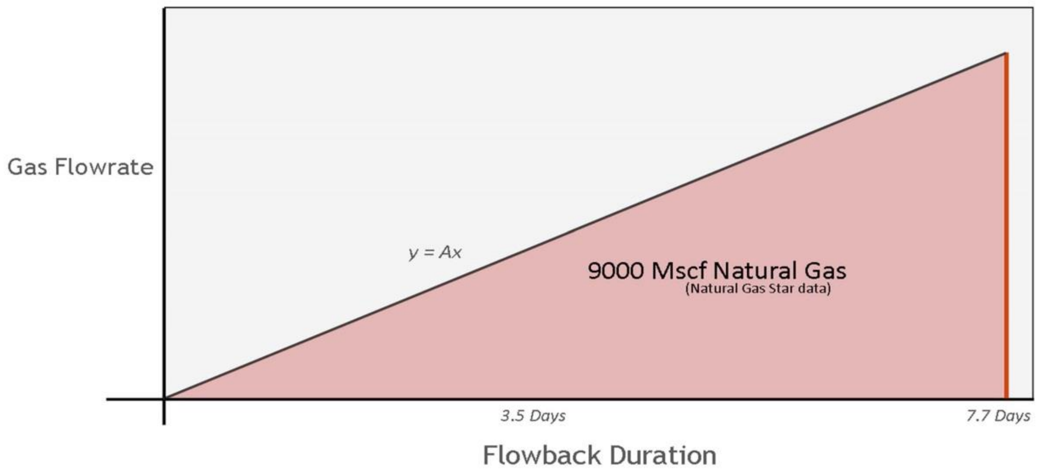
5. Research studies and reports that estimate the life-cycle greenhouse gas emission from unconventional gas are using this gross overestimate. The potential policy implications of this could be damaging to the natural gas industry, and to local and national government officials when determining the appropriate energy mixture for the future with respect to limiting greenhouse gas emissions.

6. Statistical objections to the manner in which the Bayesian methodology was employed in the previous iteration of the report were raised by Dr. Russel Evans and Dr. Jacob Dearmon, including criticism of the use a tight prior variance value, which imposes the beliefs of the researcher into the data. To date, these objections have yet to be addressed in an update of the methodologies used to estimate the mean value for methane emissions from completions. The result of this failure is a flawed estimation method that is driven by inputs of the researcher, resulting in a significantly higher estimate than the data alone can be used to support.

While Devon believes the methodology for estimating the potential emissions from well completions of wells with hydraulic fracturing is incorrect, a significant improvement could be made based simply on the survey data previously provided to EPA. In a presentation provided by Devon to EPA at the Greenhouse Gas Inventory Workshop on September 13-14, 2012, Devon provided the technical basis supporting the fact that the rate of increase of the gas production rate increases nearly linearly from the moment that the wells begin to produce gas to the time that flowback ceases, and the well is sent to production. This position is also further corroborated by the presentation by Dr. Francis O'Sullivan from MIT4. Given this fact, the appropriate use of the data from the Natural Gas Star program would be to reduce the estimate based on the difference in flowback duration for wells that are vented or flared and those that use reduced emissions completions. For example, if the Natural Gas Star data shows that a green completed well captures 9,000 Mscf of natural gas per completion, this gas captured would have increased at a near linear rate from the moment the well was first brought on flowback through the time it was put on production. If we assume, most conservatively, that gas was present at the very instant the well was put on flowback, the rate of increase of the gas rate for the average well can be solved by setting the area under the curve from x=0 to x=7.7 to 9000 for the integral

$$\int_0^{7.7} Ax\,dx$$

The line represents the relationship between the instantaneous natural gas flowrate, y, at the given time, x.

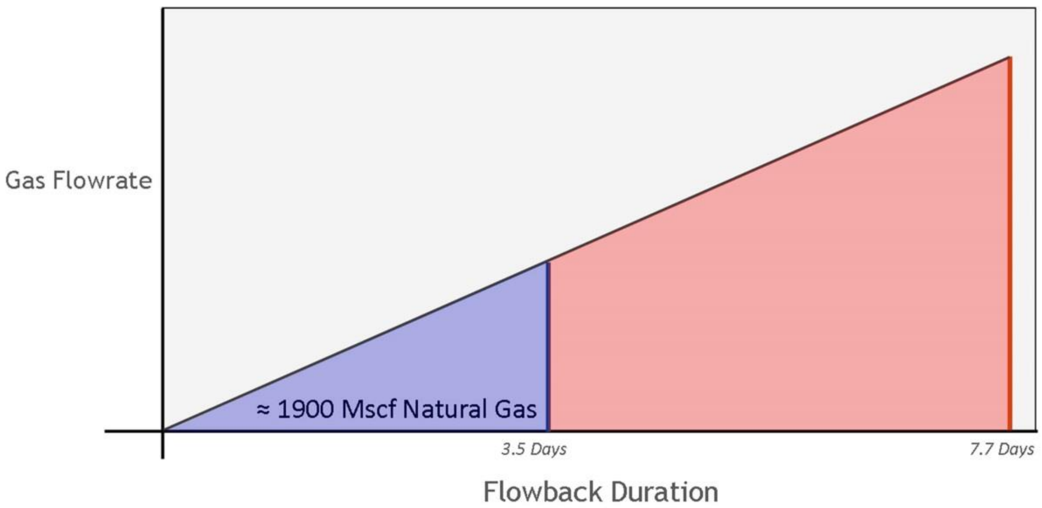


Solving for A,

$$9000 = \int_0^{7.6} Ax\,dx = A(1/2(7.7)^2)$$

$$A = \frac{9000}{1/2(7.7^2)} = 303.592\ Mscf/day^2$$

Then, knowing the rate of the increase in production rate for the average well, A, and setting x at 3.5 days, (the timeframe for those wells that are vented or flared) the area under that curve, which represents the total potential emissions from wells that do not use reduced emission completion equipment, can be estimated.



$$\int_0^{3.6} 303.592x\,dx = 303.592(1/2)(3.6^2) = 1859 \approx 1900\,Mscf/completion$$

This estimate while still very conservative would be much more reflective of actual emissions than the current EPA estimate of 9000 Mscf/completion of natural gas. Devon suggests EPA use this value, 1900 Mscf of natural gas for the potential emission factor for natural gas lost from completions from wells using hydraulic fracturing, at least until a definitive study is published which directly measures emissions from such completions. Devon believes an upcoming study being performed by the UT Austin Institute with the Environmental Defense Fund uses just that type of methodology, and therefore it will, if followed, accurately estimate methane emissions from wells completed with hydraulic fracturing. For more information please consult the annex attachments.

Comment: The footnote on Table A: CH4 Emissions from Natural Gas Systems (Tg CO2 Eq.) notes that CH4 that is captured, flared, or otherwise controlled (and not emitted to the atmosphere) has been calculated and removed from the emission totals [emphasis added]. The only reductions used by the Greenhouse Gas Inventory are those from voluntary reductions and regulatory reductions.

Voluntary reductions in emissions include those reported through the Natural Gas Star Program, and include reduced emission completions and vapor recovery units. However, Natural Gas Star data does not include any reductions for those wells which are flared, as flaring is not considered a Recommended Technology or Practice under the Natural Gas Star Program5. Regulatory reductions in the greenhouse gas inventory recognize that some states require that natural gas produced during hydraulic fractured well completions be controlled, and not vented. In these

states, the emissions from natural gas well completions are either recovered or flared. The analysis considered regulations in Wyoming and Colorado and determined that 15.1 percent of the total U.S. 2010 completions were covered by state regulations. However, this 15.1 percent represented simply the percentage of wells that were in
Colorado or Wyoming as opposed to any other state. This regulatory reduction therefore doesn't recognize the flaring of wells in any other state in the U.S. even though flaring is a very often used practice in the production sector.

Flaring is used not exclusively to limit potential greenhouse gas emissions from completions, but it is also often used due to safety concerns for the protection of industry employees. The assumption that flaring is not used where there is no state regulation mandating its use is not an accurate representation of industry practice, and it is the suggestion of Devon Energy to create and alternate category for those wells that are flared reflective of actual survey data provided in the URS Memo Data (Attachment A) Provided below.

Knowing that the actual emissions from the industry must be much smaller than estimated by the previous inventory, Devon launched a data collection effort to provide the EPA with actual emission estimates from unconventional gas wells. Devon, working with ANGA, coordinated an industry effort to provide EPA with this data. A total of eight (8) companies participated in the second data collection effort and, provided data on approximately 1,200 wells. This data is attached below as the URS Memo Data (Attachment A). This effort revealed that 92% of the wells represented were completed using reduced emission completion technology, and that of the remaining wells, 55% of those that were not completed using reduced emissions completions were flared instead of vented. Devon suggests that the EPA adjusts their inventory to reflect this industry data in the revised inventory.

Devon suggests that the EPA adds additional categories for each NEMS region as follows:

Draft: Gas Well Completions without Hydraulic Fracturing
Gas Well Completions with Hydraulic Fracturing

Proposed: Gas Well Completions without Hydraulic Fracturing
Gas Well Completions with Hydraulic Fracturing Flared
Gas Well Completions with Hydraulic Fracturing Vented
Gas Well Completions with Hydraulic Fracturing Using REC

Given the Natural Gas Star data, if EPA has a count of wells that Natural Gas Star data represents, EPA can use this particular percentage for each NEMS region to split the total number of wells. If well count data is not available to EPA, instead they can use data from the

URS Memo Data (Attachment A). Based on this count, 92% of the surveyed wells were completed using reduced emissions completion equipment. The balance of the wells was flared (4.4%) or vented (3.6%). To see how this would be applied to a certain NEMS region, take the North East for example. The North East region, by the most recent estimate contained 1675 Gas Well Completions with Hydraulic Fracturing and 274 without hydraulic fracturing. Splitting that by the categories above would have a final result of:

North East NEMS Region

Proposed:	Gas Well Completions without Hydraulic Fracturing:	274
	Gas Well Completions with Hydraulic Fracturing Flared:	74 (4.4%)
	Gas Well Completions with Hydraulic Fracturing Vented:	60 (3.6%)
	Gas Well Completions with Hydraulic Fracturing Using REC:	1541 (92%)

For regions with state regulations that require controls or flaring, those wells can be added to the category of Gas Well Completions with Hydraulic Fracturing Flared, and the balance can then be split according to the percentages above.

Each of these categories would have a unique emissions factor. This would more accurately represent the fact that while flares are also used as emissions control devices, they are an integral part of the safety of a particular site and are therefore a part of the process of completions. For this reason, completions that use flaring should not be considered as part of either a regulatory reduction or a voluntary reduction, but instead a unique process.

Gas Well Completions with Hydraulic fracturing using REC should use the original 9000 Mscf/completion from section 1 above until a better number is measured and presented through peer-reviewed scientific literature, so long as this number would be reduced by the Natural Gas Star program based voluntary reductions in Table A-6: CH4 Reductions Derived from the Natural Gas STAR Program (Gg). The potential emission factor for Gas Well Completions with Hydraulic Fracturing Vented should use improved emission factor from section 1 above of 1900 Mscf/completion of natural gas. The emission for Gas Well Completions with Hydraulic Fracturing Flared should be reduced by 93.1% to reflect the BACT standards for 98% destruction efficiency and 95% capture efficiency. If the proposed number above were adopted, this number would be 131 Mscf/completion of natural gas.

This change would present another benefit for the EPA Climate Change division, in that it would incentivize greater participation by oil and gas production companies in the Natural Gas Star program. Currently, given the URS Memo data for the amount of wells having used reduced emissions completion equipment, and comparing that number to the voluntary reductions under the GHG inventory Table A-6, it becomes clear that there are at least an appreciable number of wells that are using reduced emissions completions, but not reporting volumes to the Natural Gas Star program. Given a unique category for wells completed using reduced emissions completions equipment, producers would be more likely to report volumes to the Natural Gas Star program to reduce the overall impact, as the potential emissions number would far exceed that of the other two. The suggestions in this section, if adopted, would much more accurately represent the industry practice of flaring completion emissions of wells using hydraulic fracturing, while not irresponsibly duplicating any reductions in emissions. For more information please consult the annex attachments.

Comment: Other critical inaccuracies are addressed within the comments submitted by the American Petroleum Institute with respect to liquids unloading, the unconventional well count, and wells with plunger lifts. Devon's position on these errors and on other issues not addressed directly below can be understood by reference to the thoughtful comments presented by the American Petroleum Institute. For more information please consult the annex attachments.

Appendix A

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Revised Attachment 3: Gas Well Completion Emissions Data

January 17, 2012

Summary of New Data on Gas Well Completions

URS has assembled gas well completion data supplied by eight (8) upstream exploration and production companies in the United States. Each of these companies voluntarily provided data in the past two months. URS consolidated, blinded and summarized the data in order to avoid any anti-trust concerns. All supplied data was reviewed and used in this analysis.

This data was provided in response to a request by ANGA for actual current data that could be compared to EPA's assumptions used in the newly proposed "Oil and Natural Gas Air Pollution Standards, Subpart quad O". Some of the key EPA assumptions regarding completions were:

- Amount of flowback venting for fractured unconventional gas wells. *(EPA assumes 7623 Mscf of CH4/event, or 9175 Mscf of total gas/event).* Note: This emission estimate was originally published in the "Background Technical Support Document, Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry" in support of Subpart W of the EPA's GHG Mandatory Reporting Rule.
- Duration of flowback *(EPA assumes 3-10 days),*
- Percent of completions that are controlled *(EPA assumes 15%),*
- Flaring vs. Venting *(EPA assumes 51% venting).*

Treatment of Data

Data was gathered by distributing an empty template spreadsheet formatted to receive completions data, with a separate tab for "green completion" information and a separate tab for ordinary completion (i.e. "non-green completions").

For non-green completions, the following data was gathered on each well completion reported: date of completion, AAPG basin location, type (horizontal or vertical), formation type, whether it was a recompletion or a new well, flowback duration, choke size, casing pressure, and whether the flowback gas was flared. There were one-hundred and three (103) well completions in the non-green completion dataset from five unique companies. Only five (5) of those were recompletions, the rest were new wells.

For green completions, the following data was gathered on each well completion reported: date of completion, basin, and flowback duration (time). There were 1475 wells in the green completion dataset from six companies.

The data has been scrubbed of company name, company division, and well name, so that there would be no impression of any conflict of interest nor unintended distribution of confidential business information. The resulting detailed data is attached to this memorandum.

Using EPA's recommended method for calculating emissions from gas well completions (as listed in the proposed September 9, 2011 revisions to Subpart W of the Mandatory GHG Reporting Rule), calculations were added to the data spreadsheet, using Equation W-11B for sonic flow conditions. Sonic flow was a reasonable assumption since most upstream pressures were very high (see histogram on casing pressures reported).

$$FR = 1.27 * 10^5 * A * \sqrt{187.08 * T_u} \qquad \text{(Eq. W-11B)}$$

Where:

FR = Average flow rate in cubic feet per hour, under sonic flow conditions.
A = Cross sectional area of orifice (m^2).
T_u = Upstream temperature (degrees Kelvin).
187.08 = Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

Some of the conservative assumptions used in the calculations were as follows:

- *Equation W-11B measures 100% Gas* – The flowback fluid contains a mixture of water, hydrocarbon liquids, and hydrocarbon gas that comes back from the well, and gas flow during a flowback may start and stop. The calculations presented here assume that the flow is all gas, that no water or hydrocarbon liquids exist in this outlet stream.
- *Maximum Choke Size* – Throughout flowback, operators alter choke sizes depending on the percentage of liquid and vapor, flow rate, and pressure of the stream. For the purposes of this analysis, the data gathered was only for the maximum choke size used while the flowback is making gas. This may overpredict gas flow.
- *Maximum Casing Pressure* – Casing pressure varies depending on how long the well has been flowing, due to formation pressure changes and production pipe pressure drops. To be conservative, only the maximum casing pressure found while the flowback is making gas was used. This may overpredict the gas flowrate.
- *Temperature* – A temperature of 200 ^oF was assumed for all flowbacks. Equation results are not overly sensitive to temperature.

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Summary of Results

For non-green completions, data was summarized by basin, and then the basins were averaged to produce a national average value. As can be seen in the following attached table, the resulting non-green completion flowback rate, using EPA's methodology, was 765 Mscf of gas. This is only a small fraction (8%) of the 9175 Mscf of gas per flowback that EPA had used as a basis for the subpart quad O - Oil and Natural Gas Air Pollution Standards. There was variability among the basins, which had averages ranging from 340 Mscf to 1160 Mscf. However, all of these averages, and in fact the individual company averages, which ranged from 443 to 1455 Mscf, are far below EPA's assumed value.

The percent of wells in the dataset that were green completions was 93% of 2011 well completions. Even among the 7% that were non-green completed, 54% of those were flared (rather than directly vented). This leaves approximately 3% of the well completions in the dataset that were uncontrolled. This is far lower than EPA's assumed value of 85% of the completions that are uncontrolled, with only 15% being green completed. EPA had also assumed 50% were flared.

The average duration of non-green completions in the dataset was 3.5 days (a histogram of duration distribution is shown), and the average duration of a green completion in the dataset was 7.7 days (again, a histogram of duration distribution is shown). EPA had assumed flowback duration of 3-10 days, but the dataset shows the non-green completions to be much shorter. Only the green completions cover the 3-10 day span that EPA had assumed.

Conclusions

While the dataset is limited to eight companies and just under 1500 wells, there is a reasonable representation across many of the unconventional gas development regions that are being developed in the United States. The attachment shows 2 maps of the locations of the wells in this dataset by AAPG basin. A comparative map from the Energy Information Administration of US Shale gas plays demonstrates a good overlap with many of those developing areas.

It appears that the EPA's 9175 Mscf/completion event for unconventional fractured wells is potentially overestimated by 1200%. The ANGA data may not be robust enough to provide a definitive new national flowback emission factor because of its reliance on conservative assumptions and limited regional data. However, it is far more current, and certainly collected on a far more consistent and transparent basis than any of the data EPA used to generate its 9175 Mscf. According to the Technical Support Document (TSD) for Subpart W of the EPA's GHG Mandatory Reporting Rule the 9175 Mscf was based upon some presentations by companies at

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the EPA's voluntary Natural Gas Star program, mostly from a technology transfer session in 2004 (reference http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_TSD.pdf). While the Natural Gas Star companies presented data on their completions that were now recovered, this data was never meant to represent emissions from average well completions, was never documented with the quality needed for national inventory numbers, and in fact may represent only the subset of wells where the company had implemented their new practice.

Since EPA's proposed New Source Performance Standard for well completions and recompletions is based on a cost effectiveness analysis that was calculated using the Agency's 9175 Mscf estimate, this ANGA data calls into question the economics of requiring green completions and use of reduced-emissions-completion equipment in the newly proposed rules.

Continued dissemination and reliance upon older and less consistent information in Subpart W TSD by the agency raises serious quality concerns wherever the data may be used. The current EPA overestimate is frequently cited in studies and reports, leading to inaccurate conclusions about industry emissions and increasing the potential for federal or state governmental agencies to rely upon the inaccurate data in their decision making.

Thank you for the opportunity to provide this technical support.

Kind Regards,

Matt Harrison

Matthew R. Harrison, P.E.
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GHG and CC National Practice Leader

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ATTACHMENTS

Table 1: Summary of Compiled Data

% of Wells GC		**93%**
% of Non-GC Flared		**54%**
Average Non-GC Flowback - AAPG Basin #160A	19 Samples	1,126 mcf
Non-GC Flowback - AAPG Basin #345	28 Samples	1,031 mcf
Non-GC Flowback - AAPG Basin #360	29 Samples	386 mcf
Non-GC Flowback - AAPG Basin #430	5 Samples	943 mcf
Non-GC Flowback - AAPG Basin #535	17 Samples	340 mcf
Average Flowback of Basins		765.1 mcf
Average total flowback of all non-GC events		765.4 mcf
Estimated emissions from well completions with hydraulic fracturing (Table 4-2, EPA TSD)		**9,175 mcf**
Using Equation W-11B		

Figure 2: Distribution of Single-Event Flowback Volumes (Non-Green Completions only)

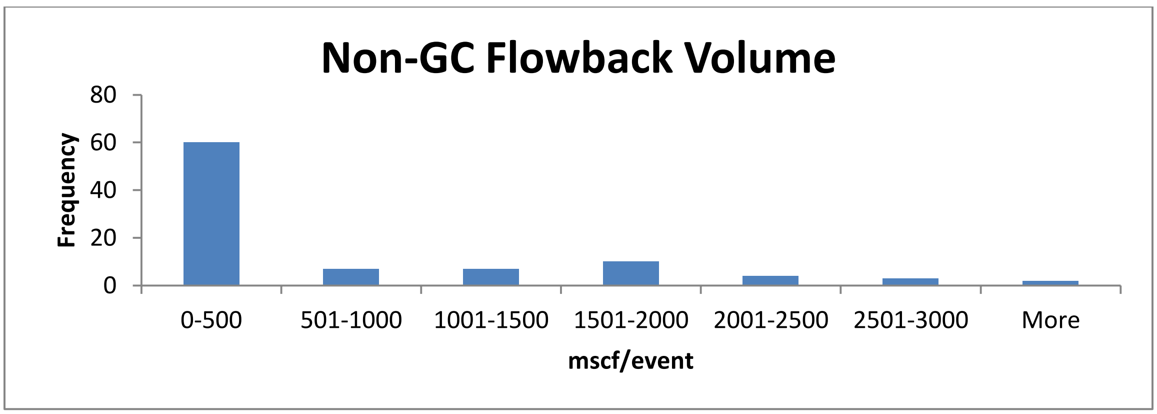


Figure 3: Distribution of Casing Pressures (Non-Green Completions only)

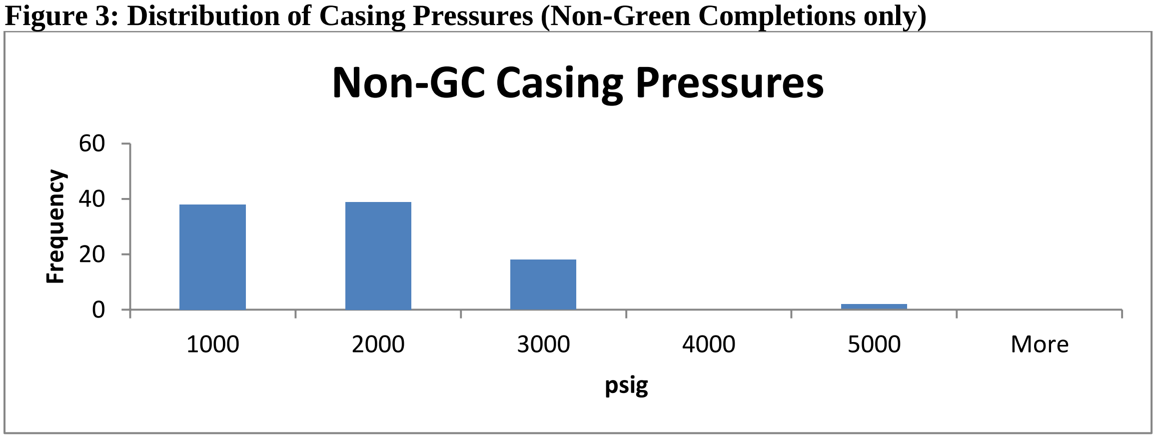


Figure 4: Distribution of Green Completion Durations

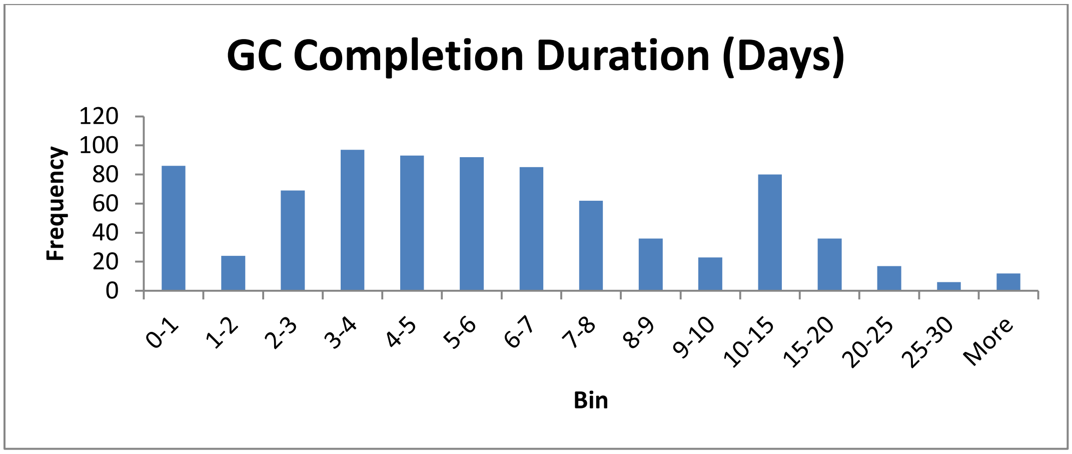


Figure 5: AAPG Basins Represented in Survey Sample (Non-GC Only)

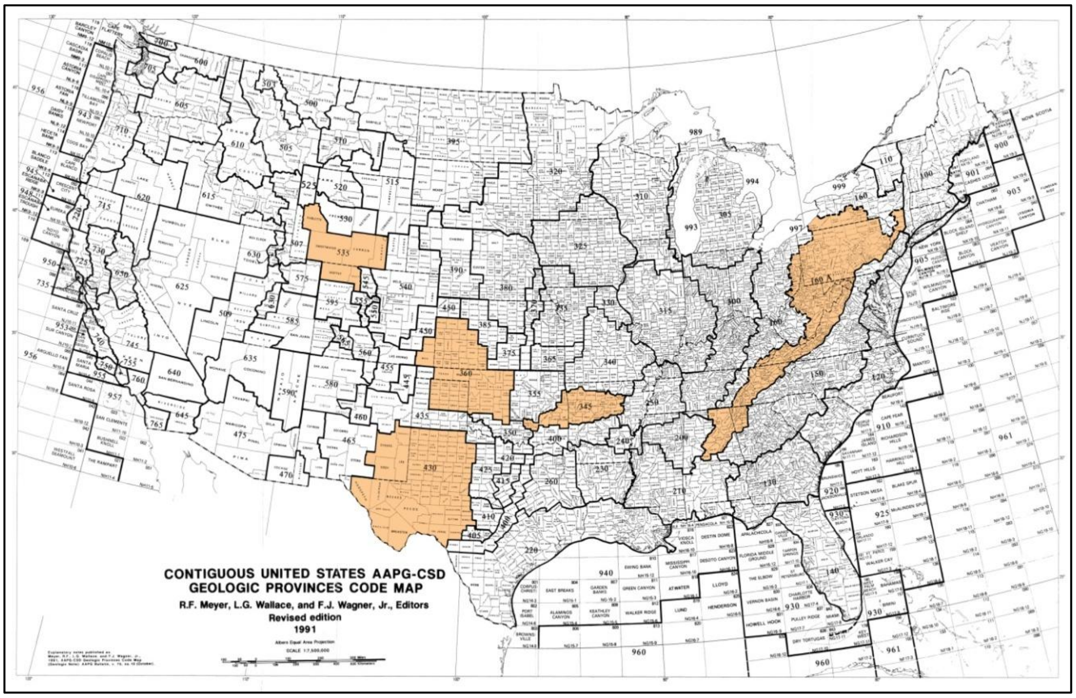
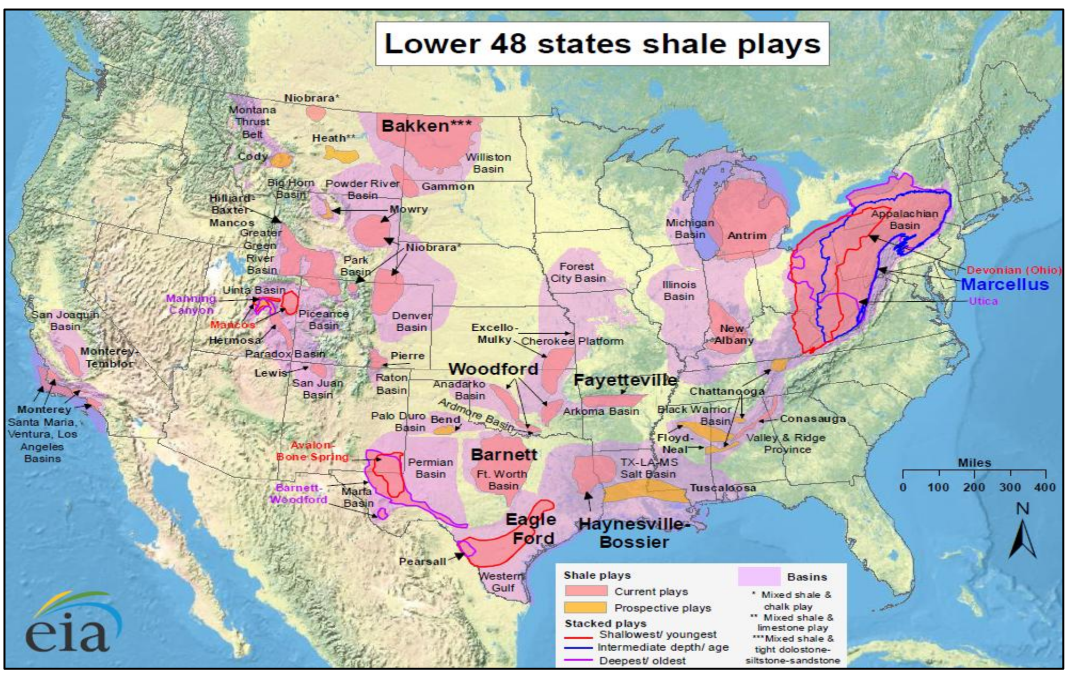


Figure 6: Location of Major Shale Plays in Continental US



Source:
http://www.slb.com/services/industry_challenges/~/media/Files/industry_challenges/unconventional_gas/other/shale_plays_lower_48.ashx

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Table 6: Survey Data (Non-Green Completions, non-GC)

Well Number	Date Well Completed	Basin	Vertical or Horizontal?	Exploration, Appraisal, or Development?	Type of Well: Tight Sand, CBM, or Shale?	New Completion or Re-Completion?	Type of Frac: H_2O, N_2, CO_2, or Other	If No, Flared or Vented?	When Making Gas: Flowback Duration (Hours)	When Making Gas: MAX Choke Size (64ths)	When Making Gas: MAX Casing Pressure (psig)	Flowback (Mscf)	Duration (Days)
R1 - Well 1	6/1/2011	Delaware	Horizontal	Development	Shale	New Completion	H2O	Flared	336	14	4175	271	14.0
R1 - Well 2	2/23/2011	Delaware	Horizontal	Development	Shale	New Completion	H2O	Flared	120	14	4200	97	5.0
R1 - Well 3	6/28/2011	Delaware	Vertical	Exploration	Shale	New Completion	H2O	Flared	257	46	500	2,236	10.7
R1 - Well 4	7/26/2011	Delaware	Horizontal	Exploration	Shale	New Completion	H2O	Flared	758	24	1900	1,795	31.6
R1 - Well 5	5/4/2011	Delaware	Vertical	Exploration	Shale	New Completion	H2O	Flared	192	20	1900	316	8.0
R1 - Well 6	2/4/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	144	24	1100	341	6.0
R1 - Well 7	2/15/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	216	24	1500	511	9.0
R1 - Well 8	2/16/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	48	18	2300	64	2.0
R1 - Well 9	2/24/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	96	18	1900	128	4.0
R1 - Well 10	6/7/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	192	22	1100	382	8.0
R1 - Well 11	6/8/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	48	24	1650	114	2.0
R1 - Well 12	6/9/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	120	20	1300	197	5.0
R1 - Well 13	7/28/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	96	22	2200	191	4.0
R1 - Well 14	7/29/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	72	20	1450	118	3.0
R1 - Well 15	8/2/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	144	64	1250	2,425	6.0
R1 - Well 16	8/27/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	72	22	1350	143	3.0
R1 - Well 17	8/28/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	120	22	1625	239	5.0
R1 - Well 18	8/28/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	96	22	1550	191	4.0
R1 - Well 19	8/30/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	96	24	1600	227	4.0
R1 - Well 20	8/31/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	96	20	700	158	4.0
R1 - Well 21	8/31/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	96	20	1080	158	4.0
R1 - Well 22	8/31/2011	Eastern Green Ri	Vertical	Development	Tight Sand	New Completion	H2O	Flared	120	20	900	197	5.0
R1 - Well 23	5/27/2011	MidCon - Cana	Horizontal	Development	Shale	New Completion	H20	Flared	59	32	2900	248	2.5
R1 - Well 24	5/18/2011	MidCon - Cana	Horizontal	Development	Shale	New Completion	H20	Flared	184	20	2400	303	7.7
R1 - Well 25	5/27/2011	MidCon - Cana	Horizontal	Development	Shale	New Completion	H20	Flared	36	20	4500	59	1.5
R1 - Well 26	6/14/2011	MidCon - Cana	Horizontal	Development	Shale	New Completion	H20	Flared	48	22	2000	96	2.0
R1 - Well 27	1/14/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	15	24	0	36	0.6
R1 - Well 28	2/4/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	118	24	0	279	4.9
R1 - Well 29	2/23/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	15	48	1350	142	0.6
R1 - Well 30	3/3/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	73	48	2025	691	3.0
R1 - Well 31	3/4/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	24	48	1020	227	1.0
R1 - Well 32	3/22/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	99	48	1750	938	4.1
R1 - Well 33	4/8/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	14	48	1380	133	0.6
R1 - Well 34	4/14/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	11	48	1350	104	0.5
R1 - Well 35	4/29/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	32	48	2400	303	1.3
R1 - Well 36	5/13/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Flared	45	48	2750	426	1.9
R1 - Well 37	5/14/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	58	24	0	137	2.4
R1 - Well 38	5/24/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Flared	79	48	2450	748	3.3
R1 - Well 39	6/2/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	23	24	0	54	1.0
R1 - Well 40	6/29/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	109	48	950	1,032	4.5
R1 - Well 41	7/1/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	31	48	650	294	1.3
R1 - Well 42	7/4/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	52	48	700	493	2.2
R1 - Well 43	7/6/2011	Granite Wash	Vertical	Development	Tight Sand	Recompletion	H2O	Vented	52	24	1550	123	2.2
R1 - Well 44	7/11/2011	Granite Wash	Vertical	Development	Tight Sand	Recompletion	H2O	Vented	35	24	0	83	1.5
R1 - Well 45	7/28/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	169	64	490	2,846	7.0
R1 - Well 46	8/2/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	53	40	950	349	2.2
R1 - Well 47	8/5/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	24	48	2100	227	1.0
R1 - Well 48	8/13/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	3	48	1850	28	0.1
R1 - Well 49	8/19/2011	Granite Wash	Horizontal	Development	Tight Sand	New Completion	H2O	Vented	85	48	850	805	3.5
R2 - Well 1	6/2/2011	160A	HORIZONTAL	Appraisal	Shale	New Completion	H2O	Flared	49	48	1675	464	2.0
R2- Well 2	6/2/2011	160A	HORIZONTAL	Appraisal	Shale	New Completion	H2O	Flared	75	48	1460	710	3.1
R2 - Well 3	6/2/2011	160A	HORIZONTAL	Appraisal	Shale	New Completion	H2O	Flared	97	48	1360	919	4.0
R2 - Well 4	1/5/2011	345	HORIZONTAL	Development	Shale	New Completion	H2O	Flared	114	48	1500	1,080	4.8
R2- Well 5	1/15/2011	345	HORIZONTAL	Development	Shale	New Completion	H2O	Flared	70	128	840	4,715	2.9
R2 - Well 6	2/12/2011	345	HORIZONTAL	Development	Shale	New Completion	H2O	Flared	81	64	740	1,364	3.4
R2 - Well 7	2/18/2011	345	HORIZONTAL	Development	Shale	New Completion	H2O	Flared	64	64	520	1,078	2.7
R2- Well 8	3/4/2011	345	HORIZONTAL	Development	Shale	New Completion	H2O	Flared	0	0	0		0.0
R2 - Well 9	3/11/2011	345	HORIZONTAL	Development	Shale	New Completion	H2O	Flared	138	48	480	1,307	5.8
R2 - Well 10	3/17/2011	345	HORIZONTAL	Development	Shale	New Completion	H2O	Flared	0	0	0		
R2- Well 11	1/31/2011	360	VERTICAL	Development		New Completion	N2	Vented	0	0	0		
R2 - Well 12	6/17/2011	360	HORIZONTAL	Development	Tight Sand	New Completion	H2O	Vented	0	0	0		

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									When Making Gas				
Well Number	Date Well Completed	Basin	Vertical or Horizontal?	Exploration, Appraisal, or Development?	Type of Well: Tight Sand, CBM, or Shale?	New Completion or Re-Completion?	Type of Frac: H_2O, N_2, CO_2, or Other	If No, Flared or Vented?	Flowback Duration (Hours)	MAX Choke Size (64ths)	MAX Casing Pressure (psig)	Flowback (Mscf)	Duration (Days)
R3 - Well 1	1/21/2011	Marcellus	Horizontal	Development	Shale	New Completion	H2O	Flared	20	32	1642	84	0.8
R3 - Well 2	1/24/2011	Marcellus	Horizontal	Development	Shale	New Completion	H2O	Flared	10	34	2450	48	0.4
R3 - Well 3	3/26/2011	Marcellus	Horizontal	Development	Shale	New Completion	H2O	Flared	13	30	2275	48	0.5
R3 - Well 4	3/26/2011	Marcellus	Horizontal	Development	Shale	New Completion	H2O	Flared	25	32	2500	105	1.0
R3 - Well 5	6/1/2011	Marcellus	Horizontal	Appraisal	Shale	New Completion	H2O	Flared	301	48	2853	2,851	12.5
R3 - Well 6	6/1/2011	Marcellus	Horizontal	Appraisal	Shale	New Completion	H2O	Flared	198	48	2239	1,875	8.3
R3 - Well 7	6/1/2011	Marcellus	Horizontal	Appraisal	Shale	New Completion	H2O	Flared	262	48	2097	2,482	10.9
R3 - Well 8	6/1/2011	Marcellus	Horizontal	Appraisal	Shale	New Completion	H2O	Flared	291	64	2100	4,900	12.1
R3 - Well 9	6/1/2011	Marcellus	Horizontal	Appraisal	Shale	New Completion	H2O	Flared	271	48	1591	2,567	11.3
R3 - Well 10	6/1/2011	Marcellus	Horizontal	Appraisal	Shale	New Completion	H2O	Flared	172	48	2106	1,629	7.2
R3 - Well 11	7/23/2011	Marcellus	Horizontal	Development	Shale	New Completion	H2O	Flared	152	48	925	1,440	6.3
R3 - Well 12	8/9/2011	Marcellus	Horizontal	Development	Shale	New Completion	H2O	Flared	70	24	2332	166	2.9
R3 - Well 13	8/26/2011	Marcellus	Horizontal	Development	Shale	New Completion	H2O	Flared	39	48	1900	369	1.6
R3 - Well 14	5/18/2011	Marcellus	Horizontal	Development	Shale	New Completion	H2O	Flared	15	48	1581	142	0.6
R3 - Well 15	8/3/2011	Marcellus	Horizontal	Development	Shale	New Completion	H2O	Flared	38	48	268	360	1.6
R3 - Well 16	8/27/2011	Marcellus	Horizontal	Development	Shale	New Completion	H2O	Flared	24	48	1266	227	1.0
R4 - Well 1	1/4/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	24	64	980	404	1.0
R4 - Well 2	1/7/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	24	128	920	1,617	1.0
R4 - Well 3	1/13/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	24	128	570	1,617	1.0
R4 - Well 4	1/17/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	24	128	491	1,617	1.0
R4 - Well 5	1/26/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	24	64	925	404	1.0
R4 - Well 6	1/29/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	23.94	64	950	403	1.0
R4 - Well 7	2/1/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	24	128	1000	1,617	1.0
R4 - Well 8	2/9/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	24	64	1000	404	1.0
R4 - Well 9	3/8/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	24	128	1124	1,617	1.0
R4 - Well 10	3/11/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	24	128	950	1,617	1.0
R4 - Well 11	3/14/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	24	64	660	404	1.0
R4 - Well 12	4/1/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	24	128	580	1,617	1.0
R4 - Well 13	4/4/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	32	128	500	2,155	1.3
R4 - Well 14	4/12/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	72	64	1200	1,212	3.0
R4 - Well 15	4/18/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	24	64	1475	404	1.0
R4 - Well 16	4/23/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	24	64	1200	404	1.0
R4 - Well 17	4/26/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	24	35	1050	121	1.0
R4 - Well 18	5/19/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	26	64	1075	438	1.1
R4 - Well 19	5/22/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	23.8	64	590	401	1.0
R4 - Well 20	5/26/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	24	64	1008	404	1.0
R4 - Well 21	5/29/2011	Woodford	Horizontal	Development	Shale	New Completion	H2O	Vented	26	64	985	438	1.1
R5 - Well 1	1/26/2011	East Texas	Vertical	Exploration	Shale	New Completion	H2O	Flared					
R5 - Well 2	1/27/2011	East Texas	Vertical	Exploration	Shale	New Completion	H2O	Flared					
R5 - Well 3	1/13/2011	Arkoma	Vertical	Development	Tight Sant	Re-Completion	N2	Vented					
R5 - Well 4	3/2/2011	Arkoma	Vertical	Development	Tight Sant	Re-Completion	N2	Vented					
R5 - Well 5	1/13/2011	Arkoma	Vertical	Development	Tight Sant	Re-Completion	N2	Vented					

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Table 7: Survey Data (Green Completions GC)

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR1 - Well 1	2/7/11	East Texas	433	18.0
GCR1 - Well 2	5/25/11	East Texas	400	16.7
GCR1 - Well 3	1/11/11	East Texas	422	17.6
GCR1 - Well 4	5/26/11	East Texas	474	19.8
GCR1 - Well 5	3/18/11	East Texas	746	31.1
GCR1 - Well 6	1/3/11	East Texas	634	26.4
GCR1 - Well 7	1/9/11	East Texas	108	4.5
GCR1 - Well 8	4/16/11	East Texas	336	14.0
GCR1 - Well 9	1/9/11	East Texas	120	5.0
GCR1 - Well 10	4/5/11	East Texas	276	11.5
GCR1 - Well 11	3/20/11	East Texas	360	15.0
GCR1 - Well 12	3/19/11	East Texas	324	13.5
GCR1 - Well 13	6/8/11	East Texas	264	11.0
GCR1 - Well 14	2/6/11	East Texas	288	12.0
GCR1 - Well 15	8/5/11	East Texas	420	17.5
GCR1 - Well 16	8/31/11	East Texas	156	6.5
GCR1 - Well 17	8/6/11	East Texas	492	20.5
GCR1 - Well 18	6/1/11	East Texas	288	12.0
GCR1 - Well 19	4/10/11	East Texas	540	22.5
GCR1 - Well 20	3/22/11	East Texas	370	15.4
GCR1 - Well 21	7/1/11	East Texas	216	9.0
GCR1 - Well 22	2/25/11	East Texas	490	20.4
GCR1 - Well 23	2/4/11	Eastern Green River	96	4.0
GCR1 - Well 24	2/15/11	Eastern Green River	72	3.0
GCR1 - Well 25	2/15/11	Eastern Green River	72	3.0
GCR1 - Well 26	2/16/11	Eastern Green River	72	3.0
GCR1 - Well 27	2/17/11	Eastern Green River	96	4.0
GCR1 - Well 28	2/25/11	Eastern Green River	96	4.0
GCR1 - Well 29	2/25/11	Eastern Green River	72	3.0

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR1 - Well 30	6/7/11	Eastern Green River	72	3.0
GCR1 - Well 31	6/8/11	Eastern Green River	72	3.0
GCR1 - Well 32	6/8/11	Eastern Green River	48	2.0
GCR1 - Well 33	6/9/11	Eastern Green River	72	3.0
GCR1 - Well 34	6/22/11	Eastern Green River	48	2.0
GCR1 - Well 35	6/22/11	Eastern Green River	72	3.0
GCR1 - Well 36	6/22/11	Eastern Green River	72	3.0
GCR1 - Well 37	6/23/11	Eastern Green River	72	3.0
GCR1 - Well 38	6/23/11	Eastern Green River	72	3.0
GCR1 - Well 39	7/28/11	Eastern Green River	120	5.0
GCR1 - Well 40	7/29/11	Eastern Green River	96	4.0
GCR1 - Well 41	1/4/11	Fort Worth Basin	48	2.0
GCR1 - Well 42	1/10/11	Fort Worth Basin	24	1.0
GCR1 - Well 43	1/10/11	Fort Worth Basin	72	3.0
GCR1 - Well 44	1/10/11	Fort Worth Basin	72	3.0
GCR1 - Well 45	1/12/11	Fort Worth Basin	24	1.0
GCR1 - Well 46	1/13/11	Fort Worth Basin	48	2.0
GCR1 - Well 47	1/17/11	Fort Worth Basin	48	2.0
GCR1 - Well 48	1/18/11	Fort Worth Basin	144	6.0
GCR1 - Well 49	1/21/11	Fort Worth Basin	144	6.0
GCR1 - Well 50	1/21/11	Fort Worth Basin	264	11.0
GCR1 - Well 51	1/24/11	Fort Worth Basin	120	5.0
GCR1 - Well 52	1/24/11	Fort Worth Basin	48	2.0
GCR1 - Well 53	1/25/11	Fort Worth Basin	168	7.0
GCR1 - Well 54	1/26/11	Fort Worth Basin	24	1.0
GCR1 - Well 55	1/26/11	Fort Worth Basin	168	7.0
GCR1 - Well 56	1/26/11	Fort Worth Basin	24	1.0
GCR1 - Well 57	1/26/11	Fort Worth Basin	144	6.0
GCR1 - Well 58	1/26/11	Fort Worth Basin	96	4.0
GCR1 - Well 59	1/27/11	Fort Worth Basin	48	2.0
GCR1 - Well 60	1/28/11	Fort Worth Basin	72	3.0
GCR1 - Well 61	1/28/11	Fort Worth Basin	96	4.0
GCR1 - Well 62	2/7/11	Fort Worth Basin	72	3.0
GCR1 - Well 63	2/7/11	Fort Worth Basin	24	1.0

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR1 - Well 64	2/9/11	Fort Worth Basin	72	3.0
GCR1 - Well 65	2/12/11	Fort Worth Basin	72	3.0
GCR1 - Well 66	2/12/11	Fort Worth Basin	48	2.0
GCR1 - Well 67	2/12/11	Fort Worth Basin	168	7.0
GCR1 - Well 68	2/13/11	Fort Worth Basin	72	3.0
GCR1 - Well 69	2/15/11	Fort Worth Basin	144	6.0
GCR1 - Well 70	2/16/11	Fort Worth Basin	96	4.0
GCR1 - Well 71	2/16/11	Fort Worth Basin	48	2.0
GCR1 - Well 72	2/17/11	Fort Worth Basin	24	1.0
GCR1 - Well 73	2/18/11	Fort Worth Basin	672	28.0
GCR1 - Well 74	2/18/11	Fort Worth Basin	672	28.0
GCR1 - Well 75	2/25/11	Fort Worth Basin	24	1.0
GCR1 - Well 76	3/18/11	Fort Worth Basin	96	4.0
GCR1 - Well 77	3/18/11	Fort Worth Basin	96	4.0
GCR1 - Well 78	3/26/11	Fort Worth Basin	72	3.0
GCR1 - Well 79	3/26/11	Fort Worth Basin	192	8.0
GCR1 - Well 80	3/26/11	Fort Worth Basin	120	5.0
GCR1 - Well 81	3/28/11	Fort Worth Basin	120	5.0
GCR1 - Well 82	4/1/11	Fort Worth Basin	24	1.0
GCR1 - Well 83	4/2/11	Fort Worth Basin	96	4.0
GCR1 - Well 84	4/3/11	Fort Worth Basin	240	10.0
GCR1 - Well 85	4/3/11	Fort Worth Basin	72	3.0
GCR1 - Well 86	4/4/11	Fort Worth Basin	240	10.0
GCR1 - Well 87	4/6/11	Fort Worth Basin	72	3.0
GCR1 - Well 88	4/9/11	Fort Worth Basin	168	7.0
GCR1 - Well 89	4/10/11	Fort Worth Basin	120	5.0
GCR1 - Well 90	4/11/11	Fort Worth Basin	336	14.0
GCR1 - Well 91	4/11/11	Fort Worth Basin	216	9.0
GCR1 - Well 92	4/13/11	Fort Worth Basin	144	6.0
GCR1 - Well 93	4/26/11	Fort Worth Basin	216	9.0
GCR1 - Well 94	4/26/11	Fort Worth Basin	216	9.0
GCR1 - Well 95	4/29/11	Fort Worth Basin	96	4.0
GCR1 - Well 96	5/1/11	Fort Worth Basin	744	31.0
GCR1 - Well 97	5/2/11	Fort Worth Basin	552	23.0

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Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR1 - Well 98	5/3/11	Fort Worth Basin	144	6.0
GCR1 - Well 99	5/3/11	Fort Worth Basin	696	29.0
GCR1 - Well 100	5/15/11	Fort Worth Basin	120	5.0
GCR1 - Well 101	5/21/11	Fort Worth Basin	48	2.0
GCR1 - Well 102	5/26/11	Fort Worth Basin	144	6.0
GCR1 - Well 103	5/26/11	Fort Worth Basin	120	5.0
GCR1 - Well 104	5/27/11	Fort Worth Basin	120	5.0
GCR1 - Well 105	5/28/11	Fort Worth Basin	72	3.0
GCR1 - Well 106	5/28/11	Fort Worth Basin	96	4.0
GCR1 - Well 107	5/31/11	Fort Worth Basin	48	2.0
GCR1 - Well 108	5/31/11	Fort Worth Basin	48	2.0
GCR1 - Well 109	6/2/11	Fort Worth Basin	288	12.0
GCR1 - Well 110	6/2/11	Fort Worth Basin	48	2.0
GCR1 - Well 111	6/9/11	Fort Worth Basin	24	1.0
GCR1 - Well 112	6/18/11	Fort Worth Basin	216	9.0
GCR1 - Well 113	6/18/11	Fort Worth Basin	120	5.0
GCR1 - Well 114	6/23/11	Fort Worth Basin	96	4.0
GCR1 - Well 115	6/23/11	Fort Worth Basin	48	2.0
GCR1 - Well 116	6/24/11	Fort Worth Basin	24	1.0
GCR1 - Well 117	6/25/11	Fort Worth Basin	24	1.0
GCR1 - Well 118	6/28/11	Fort Worth Basin	48	2.0
GCR1 - Well 119	7/11/11	Fort Worth Basin	96	4.0
GCR1 - Well 120	7/19/11	Fort Worth Basin	264	11.0
GCR1 - Well 121	8/1/11	Fort Worth Basin	240	10.0
GCR1 - Well 122	8/1/11	Fort Worth Basin	96	4.0
GCR1 - Well 123	8/1/11	Fort Worth Basin	96	4.0
GCR1 - Well 124	8/1/11	Fort Worth Basin	96	4.0
GCR1 - Well 125	8/1/11	Fort Worth Basin	96	4.0
GCR1 - Well 126	8/2/11	Fort Worth Basin	216	9.0
GCR1 - Well 127	8/9/11	Fort Worth Basin	24	1.0
GCR1 - Well 128	8/15/11	Fort Worth Basin	168	7.0
GCR1 - Well 129	8/17/11	Fort Worth Basin	120	5.0
GCR1 - Well 130	8/19/11	Fort Worth Basin	264	11.0
GCR1 - Well 131	8/19/11	Fort Worth Basin	168	7.0

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR1 - Well 132	8/23/11	Fort Worth Basin	384	16.0
GCR1 - Well 133	8/23/11	Fort Worth Basin	360	15.0
GCR1 - Well 134	8/23/11	Fort Worth Basin	384	16.0
GCR1 - Well 135	1/12/11	Fort Worth Basin	144	6.0
GCR1 - Well 136	1/12/11	Fort Worth Basin	144	6.0
GCR1 - Well 137	1/13/11	Fort Worth Basin	168	7.0
GCR1 - Well 138	1/14/11	Fort Worth Basin	192	8.0
GCR1 - Well 139	1/17/11	Fort Worth Basin	120	5.0
GCR1 - Well 140	1/18/11	Fort Worth Basin	336	14.0
GCR1 - Well 141	1/18/11	Fort Worth Basin	336	14.0
GCR1 - Well 142	1/18/11	Fort Worth Basin	576	24.0
GCR1 - Well 143	1/20/11	Fort Worth Basin	72	3.0
GCR1 - Well 144	1/21/11	Fort Worth Basin	168	7.0
GCR1 - Well 145	1/25/11	Fort Worth Basin	408	17.0
GCR1 - Well 146	1/26/11	Fort Worth Basin	168	7.0
GCR1 - Well 147	1/26/11	Fort Worth Basin	168	7.0
GCR1 - Well 148	1/27/11	Fort Worth Basin	120	5.0
GCR1 - Well 149	1/27/11	Fort Worth Basin	168	7.0
GCR1 - Well 150	2/6/11	Fort Worth Basin	288	12.0
GCR1 - Well 151	2/8/11	Fort Worth Basin	600	25.0
GCR1 - Well 152	2/8/11	Fort Worth Basin	48	2.0
GCR1 - Well 153	2/9/11	Fort Worth Basin	144	6.0
GCR1 - Well 154	2/9/11	Fort Worth Basin	192	8.0
GCR1 - Well 155	2/12/11	Fort Worth Basin	240	10.0
GCR1 - Well 156	2/12/11	Fort Worth Basin	432	18.0
GCR1 - Well 157	2/14/11	Fort Worth Basin	360	15.0
GCR1 - Well 158	2/15/11	Fort Worth Basin	192	8.0
GCR1 - Well 159	2/16/11	Fort Worth Basin	312	13.0
GCR1 - Well 160	2/17/11	Fort Worth Basin	288	12.0
GCR1 - Well 161	2/19/11	Fort Worth Basin	96	4.0
GCR1 - Well 162	2/23/11	Fort Worth Basin	24	1.0
GCR1 - Well 163	3/12/11	Fort Worth Basin	216	9.0
GCR1 - Well 164	3/21/11	Fort Worth Basin	168	7.0
GCR1 - Well 165	3/22/11	Fort Worth Basin	144	6.0

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR1 - Well 166	3/23/11	Fort Worth Basin	168	7.0
GCR1 - Well 167	3/23/11	Fort Worth Basin	168	7.0
GCR1 - Well 168	3/23/11	Fort Worth Basin	168	7.0
GCR1 - Well 169	3/24/11	Fort Worth Basin	144	6.0
GCR1 - Well 170	3/25/11	Fort Worth Basin	192	8.0
GCR1 - Well 171	3/26/11	Fort Worth Basin	96	4.0
GCR1 - Well 172	3/27/11	Fort Worth Basin	72	3.0
GCR1 - Well 173	3/28/11	Fort Worth Basin	120	5.0
GCR1 - Well 174	4/5/11	Fort Worth Basin	240	10.0
GCR1 - Well 175	4/12/11	Fort Worth Basin	72	3.0
GCR1 - Well 176	4/14/11	Fort Worth Basin	360	15.0
GCR1 - Well 177	4/15/11	Fort Worth Basin	312	13.0
GCR1 - Well 178	4/16/11	Fort Worth Basin	312	13.0
GCR1 - Well 179	4/17/11	Fort Worth Basin	72	3.0
GCR1 - Well 180	4/17/11	Fort Worth Basin	360	15.0
GCR1 - Well 181	4/18/11	Fort Worth Basin	24	1.0
GCR1 - Well 182	4/18/11	Fort Worth Basin	144	6.0
GCR1 - Well 183	4/18/11	Fort Worth Basin	264	11.0
GCR1 - Well 184	4/19/11	Fort Worth Basin	96	4.0
GCR1 - Well 185	4/19/11	Fort Worth Basin	120	5.0
GCR1 - Well 186	4/19/11	Fort Worth Basin	168	7.0
GCR1 - Well 187	4/20/11	Fort Worth Basin	96	4.0
GCR1 - Well 188	4/22/11	Fort Worth Basin	120	5.0
GCR1 - Well 189	4/23/11	Fort Worth Basin	192	8.0
GCR1 - Well 190	4/26/11	Fort Worth Basin	120	5.0
GCR1 - Well 191	4/29/11	Fort Worth Basin	48	2.0
GCR1 - Well 192	4/30/11	Fort Worth Basin	24	1.0
GCR1 - Well 193	4/30/11	Fort Worth Basin	384	16.0
GCR1 - Well 194	5/2/11	Fort Worth Basin	48	2.0
GCR1 - Well 195	5/8/11	Fort Worth Basin	144	6.0
GCR1 - Well 196	5/10/11	Fort Worth Basin	312	13.0
GCR1 - Well 197	5/10/11	Fort Worth Basin	312	13.0
GCR1 - Well 198	5/11/11	Fort Worth Basin	168	7.0
GCR1 - Well 199	5/11/11	Fort Worth Basin	288	12.0

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR1 - Well 200	5/12/11	Fort Worth Basin	144	6.0
GCR1 - Well 201	5/12/11	Fort Worth Basin	168	7.0
GCR1 - Well 202	5/12/11	Fort Worth Basin	264	11.0
GCR1 - Well 203	5/13/11	Fort Worth Basin	120	5.0
GCR1 - Well 204	5/13/11	Fort Worth Basin	144	6.0
GCR1 - Well 205	5/16/11	Fort Worth Basin	168	7.0
GCR1 - Well 206	5/17/11	Fort Worth Basin	144	6.0
GCR1 - Well 207	5/18/11	Fort Worth Basin	168	7.0
GCR1 - Well 208	5/23/11	Fort Worth Basin	96	4.0
GCR1 - Well 209	5/24/11	Fort Worth Basin	72	3.0
GCR1 - Well 210	6/3/11	Fort Worth Basin	192	8.0
GCR1 - Well 211	6/3/11	Fort Worth Basin	192	8.0
GCR1 - Well 212	6/6/11	Fort Worth Basin	192	8.0
GCR1 - Well 213	6/9/11	Fort Worth Basin	168	7.0
GCR1 - Well 214	6/14/11	Fort Worth Basin	144	6.0
GCR1 - Well 215	6/14/11	Fort Worth Basin	144	6.0
GCR1 - Well 216	6/14/11	Fort Worth Basin	144	6.0
GCR1 - Well 217	6/15/11	Fort Worth Basin	120	5.0
GCR1 - Well 218	6/20/11	Fort Worth Basin	192	8.0
GCR1 - Well 219	6/20/11	Fort Worth Basin	192	8.0
GCR1 - Well 220	6/21/11	Fort Worth Basin	168	7.0
GCR1 - Well 221	6/27/11	Fort Worth Basin	120	5.0
GCR1 - Well 222	6/28/11	Fort Worth Basin	144	6.0
GCR1 - Well 223	6/30/11	Fort Worth Basin	264	11.0
GCR1 - Well 224	7/1/11	Fort Worth Basin	264	11.0
GCR1 - Well 225	7/26/11	Fort Worth Basin	192	8.0
GCR1 - Well 226	7/27/11	Fort Worth Basin	384	16.0
GCR1 - Well 227	7/27/11	Fort Worth Basin	216	9.0
GCR1 - Well 228	7/27/11	Fort Worth Basin	288	12.0
GCR1 - Well 229	7/27/11	Fort Worth Basin	168	7.0
GCR1 - Well 230	7/29/11	Fort Worth Basin	144	6.0
GCR1 - Well 231	8/9/11	Fort Worth Basin	72	3.0
GCR1 - Well 232	8/9/11	Fort Worth Basin	168	7.0
GCR1 - Well 233	8/9/11	Fort Worth Basin	216	9.0

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR1 - Well 234	8/10/11	Fort Worth Basin	312	13.0
GCR1 - Well 235	8/15/11	Fort Worth Basin	48	2.0
GCR1 - Well 236	8/18/11	Fort Worth Basin	96	4.0
GCR1 - Well 237	8/21/11	Fort Worth Basin	216	9.0
GCR1 - Well 238	8/22/11	Fort Worth Basin	48	2.0
GCR1 - Well 239	8/22/11	Fort Worth Basin	144	6.0
GCR1 - Well 240	8/25/11	Fort Worth Basin	96	4.0
GCR1 - Well 241	1/16/11	Groesbeck	192	8.0
GCR1 - Well 242	2/23/11	Groesbeck	54	2.3
GCR1 - Well 243	4/19/11	Groesbeck	364	15.2
GCR1 - Well 244	1/21/11	Groesbeck	72	3.0
GCR1 - Well 245	7/13/11	Groesbeck	325	13.5
GCR1 - Well 246	7/14/11	Groesbeck	463	19.3
GCR1 - Well 247	3/18/11	Groesbeck	355	14.8
GCR1 - Well 248	4/12/11	North LA	294	12.3
GCR1 - Well 249	7/8/11	North LA	474	19.8
GCR1 - Well 250	2/21/11	South Texas	377	15.7
GCR1 - Well 251	7/21/11	South Texas	232	9.7
GCR1 - Well 252	3/11/11	South Texas	3	0.1
GCR1 - Well 253	4/5/11	South Texas	130	5.4
GCR1 - Well 254	8/17/11	South Texas	196	8.2
GCR1 - Well 255	8/9/11	STX - Eagleford	344	14.3
GCR1 - Well 256	8/9/11	STX - Eagleford	330	13.8
GCR2 - Well 1	8/29/2011	360		
GCR2 - Well 2	8/18/2011	415		
GCR2 - Well 3	3/23/2011	160A		
GCR2 - Well 4	3/8/2011	360		
GCR2 - Well 5	4/30/2011	360		
GCR2 - Well 6	2/21/2011	415		
GCR2 - Well 7	7/29/2011	415		
GCR2 - Well 8	2/22/2011	345	136	5.7
GCR2 - Well 9	6/1/2011	360		
GCR2 - Well 10	6/20/2011	360		
GCR2 - Well 11	4/6/2011	360		

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 12	8/31/2011	415		
GCR2 - Well 13	6/1/2011	360		
GCR2 - Well 14	6/9/2011	360		
GCR2 - Well 15	8/11/2011	415		
GCR2 - Well 16	8/30/2011	415		
GCR2 - Well 17	6/9/2011	360		
GCR2 - Well 18	3/31/2011	360		
GCR2 - Well 19	6/8/2011	360		
GCR2 - Well 20	1/8/2011	415		
GCR2 - Well 21	6/22/2011	415		
GCR2 - Well 22	6/7/2011	220		
GCR2 - Well 23	3/19/2011	360		
GCR2 - Well 24	5/2/2011	360		
GCR2 - Well 25	1/30/2011	415		
GCR2 - Well 26	5/28/2011	220		
GCR2 - Well 27	6/27/2011	415		
GCR2 - Well 28	3/21/2011	415		
GCR2 - Well 29	7/13/2011	220		
GCR2 - Well 30	1/29/2011	345		
GCR2 - Well 31	3/22/2011	360		
GCR2 - Well 32	6/29/2011	160A		
GCR2 - Well 33	4/15/2011	360		
GCR2 - Well 34	1/3/2011	360		
GCR2 - Well 35	3/30/2011	345		
GCR2 - Well 36	3/13/2011	415		
GCR2 - Well 37	5/1/2011	360		
GCR2 - Well 38	7/5/2011	360		
GCR2 - Well 39	7/13/2011	220		
GCR2 - Well 40	7/13/2011	360		
GCR2 - Well 41	4/4/2011	360		
GCR2 - Well 42	2/12/2011	345		
GCR2 - Well 43	8/15/2011	360		
GCR2 - Well 44	1/5/2011	360		
GCR2 - Well 45	7/19/2011	415		

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 46	2/9/2011	260		
GCR2 - Well 47	2/11/2011	345		
GCR2 - Well 48	3/15/2011	345		
GCR2 - Well 49	6/6/2011	220		
GCR2 - Well 50	3/28/2011	360		
GCR2 - Well 51	7/1/2011	220		
GCR2 - Well 52	5/10/2011	415		
GCR2 - Well 53	6/2/2011	360		
GCR2 - Well 54	2/24/2011	360		
GCR2 - Well 55	3/17/2011	360		
GCR2 - Well 56	1/28/2011	360		
GCR2 - Well 57	5/17/2011	360		
GCR2 - Well 58	2/26/2011	360		
GCR2 - Well 59	5/22/2011	420		
GCR2 - Well 60	8/15/2011	360		
GCR2 - Well 61	1/28/2011	345		
GCR2 - Well 62	7/11/2011	220		
GCR2 - Well 63	3/13/2011	345		
GCR2 - Well 64	2/23/2011	360		
GCR2 - Well 65	7/20/2011	415		
GCR2 - Well 66	8/29/2011	415		
GCR2 - Well 67	6/14/2011	230		
GCR2 - Well 68	6/15/2011	220		
GCR2 - Well 69	2/21/2011	360		
GCR2 - Well 70	1/8/2011	415		
GCR2 - Well 71	8/12/2011	415		
GCR2 - Well 72	2/27/2011	360		
GCR2 - Well 73	8/24/2011	415	166	6.9
GCR2 - Well 74	4/7/2011	415		
GCR2 - Well 75	7/21/2011	415		
GCR2 - Well 76	7/1/2011	220		
GCR2 - Well 77	3/19/2011	220		
GCR2 - Well 78	5/16/2011	415		
GCR2 - Well 79	3/25/2011	415		

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 80	3/24/2011	415		
GCR2 - Well 81	2/23/2011	360		
GCR2 - Well 82	6/20/2011	360		
GCR2 - Well 83	4/15/2011	220		
GCR2 - Well 84	5/8/2011	415		
GCR2 - Well 85	8/28/2011	415		
GCR2 - Well 86	5/2/2011	360		
GCR2 - Well 87	1/8/2011	360		
GCR2 - Well 88	3/14/2011	415		
GCR2 - Well 89	7/6/2011	415		
GCR2 - Well 90	6/29/2011	415		
GCR2 - Well 91	3/4/2011	415		
GCR2 - Well 92	3/12/2011	415		
GCR2 - Well 93	4/6/2011	415		
GCR2 - Well 94	3/10/2011	360		
GCR2 - Well 95	8/1/2011	415		
GCR2 - Well 96	4/3/2011	415		
GCR2 - Well 97	7/22/2011	360		
GCR2 - Well 98	6/29/2011	360		
GCR2 - Well 99	1/30/2011	415		
GCR2 - Well 100	5/22/2011	400		
GCR2 - Well 101	7/6/2011	415		
GCR2 - Well 102	6/6/2011	220		
GCR2 - Well 103	4/17/2011	415		
GCR2 - Well 104	4/8/2011	360		
GCR2 - Well 105	4/23/2011	415		
GCR2 - Well 106	4/23/2011	415		
GCR2 - Well 107	3/20/2011	415		
GCR2 - Well 108	6/15/2011	415		
GCR2 - Well 109	1/7/2011	415		
GCR2 - Well 110	2/1/2011	415		
GCR2 - Well 111	4/29/2011	360		
GCR2 - Well 112	4/17/2011	415		
GCR2 - Well 113	4/28/2011	415		

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 114	6/26/2011	415		
GCR2 - Well 115	1/2/2011	415		
GCR2 - Well 116	4/16/2011	415		
GCR2 - Well 117	5/3/2011	415		
GCR2 - Well 118	3/6/2011	345		
GCR2 - Well 119	5/21/2011	350		
GCR2 - Well 120	2/3/2011	360		
GCR2 - Well 121	6/25/2011	415		
GCR2 - Well 122	7/11/2011	415		
GCR2 - Well 123	6/1/2011	415		
GCR2 - Well 124	8/9/2011	360		
GCR2 - Well 125	4/4/2011	360		
GCR2 - Well 126	3/27/2011	415		
GCR2 - Well 127	1/12/2011	415		
GCR2 - Well 128	7/17/2011	415		
GCR2 - Well 129	2/21/2011	345	383	16.0
GCR2 - Well 130	4/20/2011	415		
GCR2 - Well 131	8/28/2011	415		
GCR2 - Well 132	7/21/2011	360		
GCR2 - Well 133	7/27/2011	415		
GCR2 - Well 134	1/12/2011	415		
GCR2 - Well 135	5/3/2011	415		
GCR2 - Well 136	5/4/2011	160A		
GCR2 - Well 137	7/12/2011	360		
GCR2 - Well 138	8/26/2011	415		
GCR2 - Well 139	7/13/2011	415		
GCR2 - Well 140	2/25/2011	415		
GCR2 - Well 141	1/30/2011	415		
GCR2 - Well 142	6/26/2011	415		
GCR2 - Well 143	4/29/2011	415		
GCR2 - Well 144	3/4/2011	415		
GCR2 - Well 145	8/19/2011	415		
GCR2 - Well 146	2/25/2011	415		
GCR2 - Well 147	2/25/2011	415		

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Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 148	4/4/2011	360		
GCR2 - Well 149	3/15/2011	230		
GCR2 - Well 150	7/20/2011	415		
GCR2 - Well 151	6/16/2011	360		
GCR2 - Well 152	2/16/2011	415		
GCR2 - Well 153	1/20/2011	415		
GCR2 - Well 154	4/15/2011	220		
GCR2 - Well 155	8/2/2011	415		
GCR2 - Well 156	5/4/2011	360		
GCR2 - Well 157	6/21/2011	415		
GCR2 - Well 158	2/21/2011	360		
GCR2 - Well 159	8/19/2011	415		
GCR2 - Well 160	2/24/2011	415		
GCR2 - Well 161	2/15/2011	415		
GCR2 - Well 162	6/7/2011	415		
GCR2 - Well 163	7/30/2011	415		
GCR2 - Well 164	2/23/2011	415		
GCR2 - Well 165	8/30/2011	415		
GCR2 - Well 166	1/27/2011	415		
GCR2 - Well 167	3/21/2011	415		
GCR2 - Well 168	4/2/2011	415		
GCR2 - Well 169	4/23/2011	415		
GCR2 - Well 170	6/12/2011	360		
GCR2 - Well 171	3/25/2011	415		
GCR2 - Well 172	4/1/2011	415		
GCR2 - Well 173	1/27/2011	415		
GCR2 - Well 174	5/12/2011	260		
GCR2 - Well 175	7/1/2011	415		
GCR2 - Well 176	6/25/2011	415		
GCR2 - Well 177	3/20/2011	415		
GCR2 - Well 178	2/16/2011	415		
GCR2 - Well 179	6/26/2011	415		
GCR2 - Well 180	4/22/2011	415		
GCR2 - Well 181	3/21/2011	415		

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 182	4/30/2011	415		
GCR2 - Well 183	2/8/2011	415		
GCR2 - Well 184	5/22/2011	415		
GCR2 - Well 185	8/7/2011	160A		
GCR2 - Well 186	6/25/2011	415		
GCR2 - Well 187	2/15/2011	415		
GCR2 - Well 188	3/29/2011	360		
GCR2 - Well 189	6/14/2011	415		
GCR2 - Well 190	7/28/2011	415		
GCR2 - Well 191	1/22/2011	415		
GCR2 - Well 192	4/27/2011	415		
GCR2 - Well 193	5/8/2011	415		
GCR2 - Well 194	4/3/2011	360		
GCR2 - Well 195	1/30/2011	415		
GCR2 - Well 196	3/26/2011	415		
GCR2 - Well 197	6/28/2011	415		
GCR2 - Well 198	6/27/2011	415		
GCR2 - Well 199	3/1/2011	415		
GCR2 - Well 200	3/23/2011	415		
GCR2 - Well 201	6/30/2011	220		
GCR2 - Well 202	6/28/2011	415		
GCR2 - Well 203	4/11/2011	360		
GCR2 - Well 204	1/29/2011	360		
GCR2 - Well 205	1/27/2011	360		
GCR2 - Well 206	1/22/2011	415		
GCR2 - Well 207	5/2/2011	415		
GCR2 - Well 208	7/21/2011	415		
GCR2 - Well 209	5/10/2011	415		
GCR2 - Well 210	2/16/2011	360		
GCR2 - Well 211	2/17/2011	415		
GCR2 - Well 212	4/4/2011	415		
GCR2 - Well 213	1/9/2011	415		
GCR2 - Well 214	3/31/2011	345		
GCR2 - Well 215	4/26/2011	415		

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 216	4/8/2011	415		
GCR2 - Well 217	6/25/2011	415		
GCR2 - Well 218	4/13/2011	415		
GCR2 - Well 219	1/25/2011	260		
GCR2 - Well 220	2/21/2011	345		
GCR2 - Well 221	1/27/2011	415		
GCR2 - Well 222	8/21/2011	415		
GCR2 - Well 223	3/23/2011	415		
GCR2 - Well 224	6/14/2011	415		
GCR2 - Well 225	6/25/2011	415		
GCR2 - Well 226	6/27/2011	160A		
GCR2 - Well 227	4/8/2011	415		
GCR2 - Well 228	7/11/2011	415		
GCR2 - Well 229	7/27/2011	415		
GCR2 - Well 230	4/15/2011	230		
GCR2 - Well 231	6/3/2011	415		
GCR2 - Well 232	3/8/2011	415		
GCR2 - Well 233	8/21/2011	415		
GCR2 - Well 234	1/9/2011	415		
GCR2 - Well 235	4/22/2011	415		
GCR2 - Well 236	6/6/2011	415		
GCR2 - Well 237	3/21/2011	415		
GCR2 - Well 238	1/21/2011	260		
GCR2 - Well 239	4/18/2011	415		
GCR2 - Well 240	1/27/2011	400		
GCR2 - Well 241	1/26/2011	415		
GCR2 - Well 242	8/5/2011	415		
GCR2 - Well 243	4/22/2011	415		
GCR2 - Well 244	2/16/2011	415		
GCR2 - Well 245	8/19/2011	415		
GCR2 - Well 246	1/4/2011	360		
GCR2 - Well 247	6/16/2011	415		
GCR2 - Well 248	4/28/2011	415		
GCR2 - Well 249	4/8/2011	415		

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 250	1/27/2011	415		
GCR2 - Well 251	4/28/2011	400		
GCR2 - Well 252	3/5/2011	415		
GCR2 - Well 253	6/22/2011	415		
GCR2 - Well 254	2/18/2011	415		
GCR2 - Well 255	6/29/2011	415		
GCR2 - Well 256	3/26/2011	415		
GCR2 - Well 257	8/24/2011	415		
GCR2 - Well 258	6/13/2011	415		
GCR2 - Well 259	7/10/2011	415		
GCR2 - Well 260	5/7/2011	160A		
GCR2 - Well 261	4/16/2011	415		
GCR2 - Well 262	2/26/2011	160A		
GCR2 - Well 263	3/6/2011	415		
GCR2 - Well 264	5/6/2011	415		
GCR2 - Well 265	6/17/2011	415		
GCR2 - Well 266	1/6/2011	415		
GCR2 - Well 267	5/23/2011	360		
GCR2 - Well 268	2/21/2011	415		
GCR2 - Well 269	2/13/2011	415		
GCR2 - Well 270	7/13/2011	415		
GCR2 - Well 271	5/4/2011	400		
GCR2 - Well 272	8/16/2011	160A		
GCR2 - Well 273	6/7/2011	415		
GCR2 - Well 274	5/10/2011	415	244	10.2
GCR2 - Well 275	3/14/2011	360		
GCR2 - Well 276	2/11/2011	360		
GCR2 - Well 277	3/1/2011	415		
GCR2 - Well 278	3/15/2011	415		
GCR2 - Well 279	8/29/2011	415		
GCR2 - Well 280	6/19/2011	415		
GCR2 - Well 281	6/16/2011	230		
GCR2 - Well 282	7/11/2011	415		
GCR2 - Well 283	2/19/2011	415		

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Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 284	6/24/2011	360		
GCR2 - Well 285	5/13/2011	415		
GCR2 - Well 286	6/17/2011	415		
GCR2 - Well 287	8/9/2011	160A		
GCR2 - Well 288	8/23/2011	415		
GCR2 - Well 289	7/23/2011	415		
GCR2 - Well 290	3/8/2011	230		
GCR2 - Well 291	7/10/2011	415		
GCR2 - Well 292	1/26/2011	360		
GCR2 - Well 293	2/22/2011	415		
GCR2 - Well 294	8/18/2011	360		
GCR2 - Well 295	8/26/2011	230		
GCR2 - Well 296	5/14/2011	160A		
GCR2 - Well 297	4/15/2011	415		
GCR2 - Well 298	4/29/2011	400		
GCR2 - Well 299	4/4/2011	415		
GCR2 - Well 300	8/10/2011	220		
GCR2 - Well 301	6/30/2011	220		
GCR2 - Well 302	4/18/2011	415		
GCR2 - Well 303	4/28/2011	415		
GCR2 - Well 304	8/17/2011	415		
GCR2 - Well 305	2/20/2011	415		
GCR2 - Well 306	3/11/2011	360		
GCR2 - Well 307	3/14/2011	230		
GCR2 - Well 308	8/29/2011	415		
GCR2 - Well 309	3/23/2011	415		
GCR2 - Well 310	5/17/2011	415		
GCR2 - Well 311	7/15/2011	415		
GCR2 - Well 312	8/29/2011	415		
GCR2 - Well 313	5/25/2011	415		
GCR2 - Well 314	6/13/2011	415		
GCR2 - Well 315	3/23/2011	415		
GCR2 - Well 316	5/23/2011	400		
GCR2 - Well 317	6/12/2011	230		

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 318	5/3/2011	220		
GCR2 - Well 319	8/11/2011	360		
GCR2 - Well 320	8/18/2011	415		
GCR2 - Well 321	4/13/2011	415		
GCR2 - Well 322	5/9/2011	230		
GCR2 - Well 323	2/26/2011	415		
GCR2 - Well 324	4/8/2011	230		
GCR2 - Well 325	8/15/2011	160A		
GCR2 - Well 326	3/31/2011	230		
GCR2 - Well 327	1/4/2011	360		
GCR2 - Well 328	7/9/2011	415		
GCR2 - Well 329	1/28/2011	360		
GCR2 - Well 330	5/1/2011	415		
GCR2 - Well 331	6/15/2011	220		
GCR2 - Well 332	4/22/2011	230		
GCR2 - Well 333	8/31/2011	415		
GCR2 - Well 334	6/20/2011	415		
GCR2 - Well 335	8/15/2011	415		
GCR2 - Well 336	2/17/2011	230		
GCR2 - Well 337	1/11/2011	415		
GCR2 - Well 338	1/28/2011	415		
GCR2 - Well 339	6/21/2011	230		
GCR2 - Well 340	6/20/2011	415		
GCR2 - Well 341	2/22/2011	415		
GCR2 - Well 342	3/2/2011	415		
GCR2 - Well 343	7/16/2011	415		
GCR2 - Well 344	6/30/2011	230		
GCR2 - Well 345	6/7/2011	360		
GCR2 - Well 346	2/24/2011	360		
GCR2 - Well 347	7/29/2011	360		
GCR2 - Well 348	3/21/2011	415		
GCR2 - Well 349	2/1/2011	260		
GCR2 - Well 350	5/14/2011	360		
GCR2 - Well 351	5/13/2011	230		

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 352	5/17/2011	360		
GCR2 - Well 353	3/8/2011	415		
GCR2 - Well 354	4/18/2011	230	114	
GCR2 - Well 355	6/14/2011	230		
GCR2 - Well 356	2/20/2011	415		
GCR2 - Well 357	5/20/2011	230		
GCR2 - Well 358	7/28/2011	360		
GCR2 - Well 359	2/17/2011	230		
GCR2 - Well 360	8/8/2011	160A		
GCR2 - Well 361	5/10/2011	160A		
GCR2 - Well 362	3/27/2011	415		
GCR2 - Well 363	6/22/2011	415		
GCR2 - Well 364	3/11/2011	415		
GCR2 - Well 365	3/4/2011	230		
GCR2 - Well 366	2/23/2011	230		
GCR2 - Well 367	4/8/2011	360		
GCR2 - Well 368	2/13/2011	220		
GCR2 - Well 369	5/4/2011	400		
GCR2 - Well 370	8/5/2011	415		
GCR2 - Well 371	5/24/2011	415		
GCR2 - Well 372	4/4/2011	230		
GCR2 - Well 373	8/25/2011	415		
GCR2 - Well 374	5/24/2011	415		
GCR2 - Well 375	7/17/2011	415		
GCR2 - Well 376	6/22/2011	415		
GCR2 - Well 377	7/15/2011	415		
GCR2 - Well 378	6/7/2011	415		
GCR2 - Well 379	3/23/2011	230		
GCR2 - Well 380	8/25/2011	415		
GCR2 - Well 381	3/2/2011	230		
GCR2 - Well 382	5/2/2011	415		
GCR2 - Well 383	5/13/2011	415		
GCR2 - Well 384	8/22/2011	360		
GCR2 - Well 385	7/22/2011	160A		

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 386	2/9/2011	230		
GCR2 - Well 387	4/27/2011	360		
GCR2 - Well 388	5/27/2011	360		
GCR2 - Well 389	7/11/2011	220		
GCR2 - Well 390	1/30/2011	415		
GCR2 - Well 391	4/15/2011	160A		
GCR2 - Well 392	3/17/2011	230		
GCR2 - Well 393	2/24/2011	230		
GCR2 - Well 394	3/10/2011	230		
GCR2 - Well 395	7/18/2011	230		
GCR2 - Well 396	1/17/2011	360		
GCR2 - Well 397	1/24/2011	230		
GCR2 - Well 398	3/10/2011	415		
GCR2 - Well 399	3/1/2011	230		
GCR2 - Well 400	7/25/2011	230		
GCR2 - Well 401	1/10/2011	230		
GCR2 - Well 402	6/23/2011	230		
GCR2 - Well 403	8/12/2011	360		
GCR2 - Well 404	1/15/2011	400		
GCR2 - Well 405	6/3/2011	415		
GCR2 - Well 406	1/27/2011	415		
GCR2 - Well 407	7/5/2011	230		
GCR2 - Well 408	7/25/2011	230		
GCR2 - Well 409	5/31/2011	230		
GCR2 - Well 410	7/1/2011	360		
GCR2 - Well 411	6/7/2011	415		
GCR2 - Well 412	4/26/2011	160A	186	
GCR2 - Well 413	3/26/2011	415		
GCR2 - Well 414	7/15/2011	415		
GCR2 - Well 415	6/23/2011	230		
GCR2 - Well 416	5/26/2011	160A		
GCR2 - Well 417	8/1/2011	230		
GCR2 - Well 418	1/10/2011	230		
GCR2 - Well 419	8/20/2011	230		

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 420	3/11/2011	230		
GCR2 - Well 421	1/31/2011	360		
GCR2 - Well 422	7/13/2011	415		
GCR2 - Well 423	7/22/2011	230		
GCR2 - Well 424	1/25/2011	260		
GCR2 - Well 425	7/10/2011	415		
GCR2 - Well 426	3/1/2011	415		
GCR2 - Well 427	6/10/2011	230		
GCR2 - Well 428	3/8/2011	415		
GCR2 - Well 429	7/25/2011	230		
GCR2 - Well 430	2/13/2011	415		
GCR2 - Well 431	3/2/2011	230		
GCR2 - Well 432	4/26/2011	230		
GCR2 - Well 433	4/21/2011	230		
GCR2 - Well 434	6/27/2011	230		
GCR2 - Well 435	7/15/2011	415		
GCR2 - Well 436	3/1/2011	415		
GCR2 - Well 437	6/29/2011	415		
GCR2 - Well 438	5/31/2011	230		
GCR2 - Well 439	3/9/2011	230		
GCR2 - Well 440	5/9/2011	230		
GCR2 - Well 441	3/23/2011	230		
GCR2 - Well 442	3/9/2011	230		
GCR2 - Well 443	6/14/2011	415		
GCR2 - Well 444	2/18/2011	230		
GCR2 - Well 445	1/21/2011	230		
GCR2 - Well 446	3/27/2011	415		
GCR2 - Well 447	6/4/2011	415		
GCR2 - Well 448	3/13/2011	415		
GCR2 - Well 449	8/6/2011	230		
GCR2 - Well 450	4/1/2011	415		
GCR2 - Well 451	8/8/2011	160A		
GCR2 - Well 452	7/15/2011	230		
GCR2 - Well 453	7/22/2011	160A		

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 454	1/7/2011	360		
GCR2 - Well 455	4/11/2011	230		
GCR2 - Well 456	3/31/2011	360		
GCR2 - Well 457	5/17/2011	230		
GCR2 - Well 458	2/23/2011	230		
GCR2 - Well 459	5/25/2011	230		
GCR2 - Well 460	7/5/2011	230		
GCR2 - Well 461	7/21/2011	230		
GCR2 - Well 462	8/25/2011	230		
GCR2 - Well 463	3/22/2011	230		
GCR2 - Well 464	6/10/2011	230		
GCR2 - Well 465	4/12/2011	230		
GCR2 - Well 466	6/10/2011	415		
GCR2 - Well 467	2/28/2011	230		
GCR2 - Well 468	5/18/2011	230		
GCR2 - Well 469	8/18/2011	230		
GCR2 - Well 470	7/21/2011	160A		
GCR2 - Well 471	4/20/2011	160A		
GCR2 - Well 472	1/7/2011	230		
GCR2 - Well 473	7/20/2011	160A		
GCR2 - Well 474	4/14/2011	230		
GCR2 - Well 475	6/23/2011	220		
GCR2 - Well 476	4/30/2011	230		
GCR2 - Well 477	6/29/2011	230		
GCR2 - Well 478	5/25/2011	360		
GCR2 - Well 479	1/19/2011	230		
GCR2 - Well 480	8/29/2011	230		
GCR2 - Well 481	1/7/2011	230		
GCR2 - Well 482	4/13/2011	230		
GCR2 - Well 483	3/10/2011	230		
GCR2 - Well 484	8/2/2011	230		
GCR2 - Well 485	1/22/2011	230		
GCR2 - Well 486	6/6/2011	230		
GCR2 - Well 487	2/8/2011	230		

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Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 488	6/25/2011	160A		
GCR2 - Well 489	7/15/2011	230		
GCR2 - Well 490	1/17/2011	230		
GCR2 - Well 491	2/25/2011	230		
GCR2 - Well 492	4/16/2011	230		
GCR2 - Well 493	8/10/2011	230		
GCR2 - Well 494	5/24/2011	160A	178	
GCR2 - Well 495	7/28/2011	415		
GCR2 - Well 496	2/27/2011	260		
GCR2 - Well 497	3/12/2011	230		
GCR2 - Well 498	8/12/2011	230		
GCR2 - Well 499	5/28/2011	230		
GCR2 - Well 500	6/21/2011	230		
GCR2 - Well 501	4/8/2011	230		
GCR2 - Well 502	1/7/2011	230		
GCR2 - Well 503	8/15/2011	230		
GCR2 - Well 504	6/6/2011	230		
GCR2 - Well 505	3/18/2011	230		
GCR2 - Well 506	2/23/2011	415		
GCR2 - Well 507	3/1/2011	415		
GCR2 - Well 508	1/3/2011	230		
GCR2 - Well 509	4/27/2011	230		
GCR2 - Well 510	7/2/2011	160A		
GCR2 - Well 511	7/28/2011	415		
GCR2 - Well 512	1/12/2011	230		
GCR2 - Well 513	7/15/2011	230		
GCR2 - Well 514	3/17/2011	230		
GCR2 - Well 515	7/27/2011	230		
GCR2 - Well 516	3/15/2011	230		
GCR2 - Well 517	3/2/2011	415		
GCR2 - Well 518	1/8/2011	230		
GCR2 - Well 519	7/6/2011	230		
GCR2 - Well 520	6/25/2011	230		
GCR2 - Well 521	7/22/2011	160A		

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 522	7/21/2011	160A	139	
GCR2 - Well 523	6/24/2011	230		
GCR2 - Well 524	8/9/2011	230		
GCR2 - Well 525	5/5/2011	230		
GCR2 - Well 526	1/21/2011	230		
GCR2 - Well 527	8/16/2011	230		
GCR2 - Well 528	8/3/2011	230		
GCR2 - Well 529	4/13/2011	230		
GCR2 - Well 530	7/29/2011	230		
GCR2 - Well 531	7/28/2011	230		
GCR2 - Well 532	4/9/2011	230		
GCR2 - Well 533	3/18/2011	260		
GCR2 - Well 534	6/13/2011	260		
GCR2 - Well 535	1/8/2011	230		
GCR2 - Well 536	1/31/2011	230		
GCR2 - Well 537	3/23/2011	230		
GCR2 - Well 538	5/19/2011	230		
GCR2 - Well 539	4/4/2011	230		
GCR2 - Well 540	7/14/2011	415		
GCR2 - Well 541	8/1/2011	230		
GCR2 - Well 542	1/27/2011	230		
GCR2 - Well 543	6/17/2011	260		
GCR2 - Well 544	5/31/2011	230		
GCR2 - Well 545	6/29/2011	230		
GCR2 - Well 546	8/29/2011	260		
GCR2 - Well 547	5/14/2011	230		
GCR2 - Well 548	8/27/2011	230		
GCR2 - Well 549	6/9/2011	230		
GCR2 - Well 550	6/24/2011	230		
GCR2 - Well 551	3/4/2011	230		
GCR2 - Well 552	3/2/2011	415		
GCR2 - Well 553	8/31/2011	160A		
GCR2 - Well 554	3/26/2011	415		
GCR2 - Well 555	6/1/2011	230		

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 556	8/25/2011	415		
GCR2 - Well 557	8/12/2011	230		
GCR2 - Well 558	8/8/2011	160A		
GCR2 - Well 559	3/26/2011	415		
GCR2 - Well 560	8/10/2011	230		
GCR2 - Well 561	8/8/2011	160A		
GCR2 - Well 562	8/12/2011	230		
GCR2 - Well 563	2/26/2011	230		
GCR2 - Well 564	8/8/2011	160A		
GCR2 - Well 565	1/21/2011	230		
GCR2 - Well 566	7/5/2011	230		
GCR2 - Well 567	5/17/2011	230		
GCR2 - Well 568	4/30/2011	230		
GCR2 - Well 569	2/25/2011	230		
GCR2 - Well 570	2/9/2011	230		
GCR2 - Well 571	7/12/2011	230		
GCR2 - Well 572	7/1/2011	230	139	5.8
GCR2 - Well 573	8/15/2011	230		
GCR2 - Well 574	1/12/2011	230		
GCR2 - Well 575	8/4/2011	230		
GCR2 - Well 576	7/15/2011	230		
GCR2 - Well 577	8/13/2011	230		
GCR2 - Well 578	8/29/2011	230		
GCR2 - Well 579	7/6/2011	230		
GCR2 - Well 580	8/29/2011	230		
GCR2 - Well 581	8/18/2011	230		
GCR2 - Well 582	7/19/2011	230		
GCR2 - Well 583	8/24/2011	230		
GCR2 - Well 584	7/11/2011	230		
GCR2 - Well 585	7/22/2011	230		
GCR2 - Well 586	1/18/2011	230		
GCR2 - Well 587	8/10/2011	230		
GCR2 - Well 588	8/30/2011	230		
GCR2 - Well 589	2/24/2011	230		

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Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 590	8/18/2011	230		
GCR2 - Well 591	6/20/2011	160A		
GCR2 - Well 592	6/10/2011	230		
GCR2 - Well 593	8/9/2011	160A		
GCR2 - Well 594	8/10/2011	230		
GCR2 - Well 595	1/7/2011	360		
GCR2 - Well 596	3/30/2011	220		
GCR2 - Well 597	3/19/2011	230		
GCR2 - Well 598	4/23/2011	230		
GCR2 - Well 599	2/22/2011	230		
GCR2 - Well 600	2/18/2011	230		
GCR2 - Well 601	5/3/2011	230		
GCR2 - Well 602	3/19/2011	230		
GCR2 - Well 603	5/31/2011	230		
GCR2 - Well 604	8/8/2011	160A		
GCR2 - Well 605	6/2/2011	230		
GCR2 - Well 606	5/13/2011	230		
GCR2 - Well 607	5/10/2011	230		
GCR2 - Well 608	4/6/2011	160A		
GCR2 - Well 609	6/20/2011	230		
GCR2 - Well 610	8/14/2011	230		
GCR2 - Well 611	8/12/2011	230		
GCR2 - Well 612	7/27/2011	230		
GCR2 - Well 613	4/4/2011	230		
GCR2 - Well 614	8/26/2011	230		
GCR2 - Well 615	7/14/2011	230		
GCR2 - Well 616	2/22/2011	230		
GCR2 - Well 617	3/4/2011	160A		
GCR2 - Well 618	4/23/2011	230		
GCR2 - Well 619	6/28/2011	230		
GCR2 - Well 620	7/30/2011	230		
GCR2 - Well 621	7/1/2011	160A		
GCR2 - Well 622	3/4/2011	160A		
GCR2 - Well 623	6/20/2011	160A		

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR2 - Well 624	6/22/2011	160A		
GCR2 - Well 625	3/2/2011	415		
GCR2 - Well 626	6/11/2011	160A		
GCR2 - Well 627	6/20/2011	160A		
GCR2 - Well 628	2/7/2011	160A	795	33.1
GCR2 - Well 629	4/6/2011	160A		
GCR2 - Well 630	6/21/2011	160A		
GCR2 - Well 631	2/11/2011	160A		
GCR2 - Well 632	6/22/2011	160A		
GCR2 - Well 633	8/9/2011	160A		
GCR2 - Well 634	2/7/2011	160A		
GCR2 - Well 635	2/22/2011	160A		
GCR2 - Well 636	4/10/2011	160A		
GCR2 - Well 637	2/27/2011	160A		
GCR2 - Well 638	5/1/2011	160A		
GCR2 - Well 639	2/7/2011	160A		
GCR2 - Well 640	3/2/2011	360		
GCR2 - Well 641	2/11/2011	160A		
GCR2 - Well 642	2/27/2011	160A		
GCR2 - Well 643	8/17/2011	160A		
GCR2 - Well 644	4/10/2011	160A		
GCR2 - Well 645	2/20/2011	160A		
GCR2 - Well 646	6/11/2011	160A		
GCR2 - Well 647	2/20/2011	160A		
GCR2 - Well 648	1/14/2011	160A		
GCR2 - Well 649	6/30/2011	160A		
GCR2 - Well 650	3/20/2011	345		
GCR2 - Well 651	3/21/2011	345		
GCR3 - Well 1	3/17/2011	Green River Basin - Pinedale	63	2.6
GCR3 - Well 2	3/16/2011	Green River Basin - Pinedale	111	4.6
GCR3 - Well 3	3/22/2011	Green River Basin - Pinedale	63	2.6
GCR3 - Well 4	3/21/2011	Green River Basin - Pinedale	63	2.6
GCR3 - Well 5	3/26/2011	Green River Basin - Pinedale	89	3.7
GCR3 - Well 6	3/27/2011	Green River Basin - Pinedale	89	3.7

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR3 - Well 7	4/7/2011	Green River Basin - Pinedale	46	1.9
GCR3 - Well 8	4/2/2011	Green River Basin - Pinedale	55	2.3
GCR3 - Well 9	4/6/2011	Green River Basin - Pinedale	72	3.0
GCR3 - Well 10	4/1/2011	Green River Basin - Pinedale	65	2.7
GCR3 - Well 11	4/11/2011	Green River Basin - Pinedale	109	4.5
GCR3 - Well 12	4/12/2011	Green River Basin - Pinedale	111	4.6
GCR3 - Well 13	4/16/2011	Green River Basin - Pinedale	108	4.5
GCR3 - Well 14	4/17/2011	Green River Basin - Pinedale	111	4.6
GCR3 - Well 15	4/22/2011	Green River Basin - Pinedale	113	4.7
GCR3 - Well 16	4/21/2011	Green River Basin - Pinedale	86	3.6
GCR3 - Well 17	4/26/2011	Green River Basin - Pinedale	132	5.5
GCR3 - Well 18	5/1/2011	Green River Basin - Pinedale	89	3.7
GCR3 - Well 19	4/27/2011	Green River Basin - Pinedale	87	3.6
GCR3 - Well 20	5/2/2011	Green River Basin - Pinedale	86	3.6
GCR3 - Well 21	5/6/2011	Green River Basin - Pinedale	87	3.6
GCR3 - Well 22	5/7/2011	Green River Basin - Pinedale	92	3.8
GCR3 - Well 23	5/11/2011	Green River Basin - Pinedale	89	3.7
GCR3 - Well 24	5/12/2011	Green River Basin - Pinedale	67	2.8
GCR3 - Well 25	5/16/2011	Green River Basin - Pinedale	81	3.4
GCR3 - Well 26	5/17/2011	Green River Basin - Pinedale	94	3.9
GCR3 - Well 27	5/21/2011	Green River Basin - Pinedale	74	3.1
GCR3 - Well 28	5/22/2011	Green River Basin - Pinedale	88	3.7
GCR3 - Well 29	5/27/2011	Green River Basin - Pinedale	81	3.4
GCR3 - Well 30	5/26/2011	Green River Basin - Pinedale	109	4.5
GCR3 - Well 31	5/31/2011	Green River Basin - Pinedale	101	4.2
GCR3 - Well 32	5/31/2011	Green River Basin - Pinedale	64	2.7
GCR3 - Well 33	6/6/2011	Green River Basin - Pinedale	101	4.2
GCR3 - Well 34	6/5/2011	Green River Basin - Pinedale	110	4.6
GCR3 - Well 35	6/10/2011	Green River Basin - Pinedale	111	4.6
GCR3 - Well 36	6/16/2011	Green River Basin - Pinedale	88	3.7
GCR3 - Well 37	6/11/2011	Green River Basin - Pinedale	85	3.5
GCR3 - Well 38	6/17/2011	Green River Basin - Pinedale	68	2.8
GCR3 - Well 39	6/21/2011	Green River Basin - Pinedale	132	5.5
GCR3 - Well 40	6/26/2011	Green River Basin - Pinedale	153	6.4

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Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR3 - Well 41	6/22/2011	Green River Basin - Pinedale	102	4.3
GCR3 - Well 42	6/27/2011	Green River Basin - Pinedale	135	5.6
GCR3 - Well 43	7/1/2011	Green River Basin - Pinedale	112	4.7
GCR3 - Well 44	7/5/2011	Green River Basin - Pinedale	60	2.5
GCR3 - Well 45	7/10/2011	Green River Basin - Pinedale	96	4.0
GCR3 - Well 46	7/6/2011	Green River Basin - Pinedale	66	2.8
GCR3 - Well 47	7/11/2011	Green River Basin - Pinedale	72	3.0
GCR3 - Well 48	7/16/2011	Green River Basin - Pinedale	65	2.7
GCR3 - Well 49	7/15/2011	Green River Basin - Pinedale	87	3.6
GCR3 - Well 50	7/21/2011	Green River Basin - Pinedale	92	3.8
GCR3 - Well 51	7/20/2011	Green River Basin - Pinedale	88	3.7
GCR3 - Well 52	7/25/2011	Green River Basin - Pinedale	96	4.0
GCR3 - Well 53	7/26/2011	Green River Basin - Pinedale	90	3.8
GCR3 - Well 54	7/30/2011	Green River Basin - Pinedale	89	3.7
GCR3 - Well 55	7/31/2011	Green River Basin - Pinedale	86	3.6
GCR3 - Well 56	8/7/2011	Green River Basin - Pinedale	90	3.8
GCR3 - Well 57	8/6/2011	Green River Basin - Pinedale	108	4.5
GCR3 - Well 58	8/11/2011	Green River Basin - Pinedale	129	5.4
GCR3 - Well 59	8/12/2011	Green River Basin - Pinedale	118	4.9
GCR3 - Well 60	8/16/2011	Green River Basin - Pinedale	113	4.7
GCR3 - Well 61	8/15/2011	Green River Basin - Pinedale	122	5.1
GCR3 - Well 62	8/20/2011	Green River Basin - Pinedale	111	4.6
GCR3 - Well 63	8/21/2011	Green River Basin - Pinedale	90	3.8
GCR3 - Well 64	8/24/2011	Green River Basin - Pinedale	111	4.6
GCR3 - Well 65	8/29/2011	Green River Basin - Pinedale	90	3.8
GCR3 - Well 66	8/25/2011	Green River Basin - Pinedale	89	3.7
GCR3 - Well 67	8/30/2011	Green River Basin - Pinedale	88	3.7
GCR3 - Well 68	1/6/2011	TX-LA Salt Basin - Haynesville	113	4.7
GCR3 - Well 69	1/14/2011	TX-LA Salt Basin - Haynesville	118	4.9
GCR3 - Well 70	1/28/2011	TX-LA Salt Basin - Haynesville	100	4.2
GCR3 - Well 71	1/27/2011	TX-LA Salt Basin - Haynesville	115	4.8
GCR3 - Well 72	2/5/2011	TX-LA Salt Basin - Haynesville	78	3.3
GCR3 - Well 73	2/7/2011	TX-LA Salt Basin - Haynesville	77	3.2
GCR3 - Well 74	2/15/2011	TX-LA Salt Basin - Haynesville	150	6.3

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR3 - Well 75	2/14/2011	TX-LA Salt Basin - Haynesville	149	6.2
GCR3 - Well 76	3/2/2011	TX-LA Salt Basin - Haynesville	123	5.1
GCR3 - Well 77	3/9/2011	TX-LA Salt Basin - Haynesville	103	4.3
GCR3 - Well 78	3/10/2011	TX-LA Salt Basin - Haynesville	103	4.3
GCR3 - Well 79	4/9/2011	TX-LA Salt Basin - Haynesville	114	4.8
GCR3 - Well 80	4/18/2011	TX-LA Salt Basin - Haynesville	141	5.9
GCR3 - Well 81	4/19/2011	TX-LA Salt Basin - Haynesville	138	5.8
GCR3 - Well 82	4/20/2011	TX-LA Salt Basin - Haynesville	142	5.9
GCR3 - Well 83	4/23/2011	TX-LA Salt Basin - Haynesville	172	7.2
GCR3 - Well 84	5/1/2011	TX-LA Salt Basin - Haynesville	116	4.8
GCR3 - Well 85	5/2/2011	TX-LA Salt Basin - Haynesville	115	4.8
GCR3 - Well 86	5/14/2011	TX-LA Salt Basin - Haynesville	159	6.6
GCR3 - Well 87	5/15/2011	TX-LA Salt Basin - Haynesville	153	6.4
GCR3 - Well 88	6/1/2011	TX-LA Salt Basin - Haynesville	111	4.6
GCR3 - Well 89	6/9/2011	TX-LA Salt Basin - Haynesville	117	4.9
GCR3 - Well 90	6/7/2011	TX-LA Salt Basin - Haynesville	118	4.9
GCR3 - Well 91	6/30/2011	TX-LA Salt Basin - Haynesville	106	4.4
GCR3 - Well 92	7/1/2011	TX-LA Salt Basin - Haynesville	108	4.5
GCR3 - Well 93	7/29/2011	TX-LA Salt Basin - Haynesville	120	5.0
GCR3 - Well 94	7/28/2011	TX-LA Salt Basin - Haynesville	120	5.0
GCR3 - Well 95	8/21/2011	TX-LA Salt Basin - Haynesville	120	5.0
GCR3 - Well 96	8/22/2011	TX-LA Salt Basin - Haynesville	115	4.8
GCR3 - Well 97	8/30/2011	TX-LA Salt Basin - Haynesville	136	5.7
GCR3 - Well 98	8/29/2011	TX-LA Salt Basin - Haynesville	138	5.8
GCR4 - Well 1	1/11/2011	Anadarko	10	0.4
GCR4 - Well 2	02/20/11	Anadarko	10	0.4
GCR4 - Well 3	1/18/2011	Anadarko	10	0.4
GCR4 - Well 4	03/26/11	Anadarko	10	0.4
GCR4 - Well 5	2/9/2011	Anadarko	10	0.4
GCR4 - Well 6	04/11/11	Anadarko	10	0.4
GCR4 - Well 7	2/16/2011	Anadarko	10	0.4
GCR4 - Well 8	3/16/2011	Anadarko	10	0.4
GCR4 - Well 9	03/08/11	Anadarko	10	0.4
GCR4 - Well 10	4/1/2011	Anadarko	10	0.4

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR4 - Well 11	07/05/11	Anadarko	10	0.4
GCR4 - Well 12	7/12/2011	Anadarko	10	0.4
GCR4 - Well 13	04/27/11	Anadarko	10	0.4
GCR4 - Well 14	8/2/2011	Anadarko	10	0.4
GCR4 - Well 15	07/19/11	Anadarko	10	0.4
GCR4 - Well 16	6/20/2011	Anadarko	10	0.4
GCR4 - Well 17	08/09/11	Anadarko	10	0.4
GCR4 - Well 18	8/16/2011	Anadarko	10	0.4
GCR5 - Well 1	1/1/2011	Haynesville	6	0.3
GCR5 - Well 2	1/4/2011	Haynesville	10	0.4
GCR5 - Well 3	1/12/2011	Haynesville	15	0.6
GCR5 - Well 4	1/13/2011	Haynesville	15	0.6
GCR5 - Well 5	1/14/2011	Haynesville	11	0.5
GCR5 - Well 6	1/15/2011	Haynesville	11	0.5
GCR5 - Well 7	1/28/2011	Haynesville	4	0.2
GCR5 - Well 8	1/29/2011	Haynesville	4	0.2
GCR5 - Well 9	2/8/2011	Haynesville	14	0.6
GCR5 - Well 10	2/19/2011	Haynesville	5	0.2
GCR5 - Well 11	2/20/2011	Haynesville	14	0.6
GCR5 - Well 12	2/21/2011	Haynesville	9	0.4
GCR5 - Well 13	3/2/2011	Haynesville	16	0.7
GCR5 - Well 14	3/2/2011	Haynesville	12	0.5
GCR5 - Well 15	3/3/2011	Haynesville	12	0.5
GCR5 - Well 16	3/5/2011	Haynesville	12	0.5
GCR5 - Well 17	3/5/2011	Haynesville	12	0.5
GCR5 - Well 18	3/22/2011	Haynesville	13	0.5
GCR5 - Well 19	3/24/2011	Haynesville	19	0.8
GCR5 - Well 20	3/24/2011	Haynesville	16	0.7
GCR5 - Well 21	3/29/2011	Haynesville	13	0.5
GCR5 - Well 22	4/4/2011	Haynesville	11	0.5
GCR5 - Well 23	4/12/2011	Haynesville	13	0.5
GCR5 - Well 24	4/14/2011	Haynesville	15	0.6
GCR5 - Well 25	4/14/2011	Haynesville	14	0.6
GCR5 - Well 26	4/18/2011	Haynesville	15	0.6

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR5 - Well 27	4/26/2011	Haynesville	22	0.9
GCR5 - Well 28	4/25/2011	Haynesville	14	0.6
GCR5 - Well 29	5/4/2011	Haynesville	10	0.4
GCR5 - Well 30	5/6/2011	Haynesville	8	0.3
GCR5 - Well 31	5/12/2011	Haynesville	11	0.5
GCR5 - Well 32	5/20/2011	Haynesville	10	0.4
GCR5 - Well 33	6/1/2011	Haynesville	7	0.3
GCR5 - Well 34	6/5/2011	Haynesville	13	0.5
GCR5 - Well 35	6/13/2011	Haynesville	13	0.5
GCR5 - Well 36	6/17/2011	Haynesville	3	0.1
GCR5 - Well 37	6/24/2011	Haynesville	5	0.2
GCR5 - Well 38	7/4/2011	Haynesville	15	0.6
GCR5 - Well 39	7/10/2011	Haynesville	13	0.5
GCR5 - Well 40	7/14/2011	Haynesville	14	0.6
GCR5 - Well 41	7/23/2011	Haynesville	13	0.5
GCR5 - Well 42	7/23/2011	Haynesville	17	0.7
GCR5 - Well 43	8/4/2011	Haynesville	11	0.5
GCR5 - Well 44	8/13/2011	Haynesville	12	0.5
GCR5 - Well 45	8/13/2011	Haynesville	12	0.5
GCR5 - Well 46	9/28/2011	Haynesville	11	0.5
GCR5 - Well 47	8/31/2011	Haynesville	11	0.5
GCR5 - Well 48	8/31/2011	Haynesville	11	0.5
GCR5 - Well 49	9/15/2011	Haynesville		0.0
GCR5 - Well 50	10/6/2011	Haynesville	8	0.3
GCR5 - Well 51	10/14/2011	Haynesville	8	0.3
GCR5 - Well 52	10/21/2011	Haynesville	7	0.3
GCR5 - Well 53	11/3/2011	Haynesville	3	0.1
GCR6 - Well 1	6/22/2011	Appalachia		
GCR6 - Well 2	6/3/2011	Appalachia		
GCR6 - Well 3	4/16/2011	Appalachia		
GCR6 - Well 4	4/14/2011	Appalachia		
GCR6 - Well 5	4/12/2011	Appalachia		
GCR6 - Well 6	6/6/2011	Appalachia		
GCR6 - Well 7	6/4/2011	Appalachia		

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Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR6 - Well 8	2/15/2011	Appalachia		
GCR6 - Well 9	2/13/2011	Appalachia		
GCR6 - Well 10	2/11/2011	Appalachia		
GCR6 - Well 11	12/29/2010	Arkoma	72	3.0
GCR6 - Well 12	12/22/2010	Arkoma	288	12.0
GCR6 - Well 13	12/23/2010	Arkoma	288	12.0
GCR6 - Well 14	12/22/2010	Arkoma	312	13.0
GCR6 - Well 15	12/23/2010	Arkoma	312	13.0
GCR6 - Well 16	12/27/2010	Arkoma	216	9.0
GCR6 - Well 17	12/28/2010	Arkoma	192	8.0
GCR6 - Well 18	12/29/2010	Arkoma	168	7.0
GCR6 - Well 19	12/31/2010	Arkoma	192	8.0
GCR6 - Well 20	12/31/2010	Arkoma	192	8.0
GCR6 - Well 21	1/6/2011	Arkoma	144	6.0
GCR6 - Well 22	1/1/2011	Arkoma	264	11.0
GCR6 - Well 23	12/30/2010	Arkoma	312	13.0
GCR6 - Well 24	1/1/2011	Arkoma	288	12.0
GCR6 - Well 25	1/1/2011	Arkoma	312	13.0
GCR6 - Well 26	1/2/2011	Arkoma	288	12.0
GCR6 - Well 27	12/30/2010	Arkoma	360	15.0
GCR6 - Well 28	12/29/2010	Arkoma	384	16.0
GCR6 - Well 29	12/29/2010	Arkoma	384	16.0
GCR6 - Well 30	1/7/2011	Arkoma	240	10.0
GCR6 - Well 31	1/7/2011	Arkoma	312	13.0
GCR6 - Well 32	1/6/2011	Arkoma	336	14.0
GCR6 - Well 33	1/8/2011	Arkoma	288	12.0
GCR6 - Well 34	12/29/2010	Arkoma	552	23.0
GCR6 - Well 35	1/17/2011	Arkoma	120	5.0
GCR6 - Well 36	1/18/2011	Arkoma	96	4.0
GCR6 - Well 37	1/18/2011	Arkoma	96	4.0
GCR6 - Well 38	1/12/2011	Arkoma	288	12.0
GCR6 - Well 39	1/13/2011	Arkoma	264	11.0
GCR6 - Well 40	1/12/2011	Arkoma	288	12.0
GCR6 - Well 41	1/15/2011	Arkoma	264	11.0

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR6 - Well 42	1/14/2011	Arkoma	288	12.0
GCR6 - Well 43	1/21/2011	Arkoma	144	6.0
GCR6 - Well 44	1/19/2011	Arkoma	192	8.0
GCR6 - Well 45	1/21/2011	Arkoma	168	7.0
GCR6 - Well 46	1/22/2011	Arkoma	144	6.0
GCR6 - Well 47	1/17/2011	Arkoma	264	11.0
GCR6 - Well 48	1/24/2011	Arkoma	96	4.0
GCR6 - Well 49	1/15/2011	Arkoma	312	13.0
GCR6 - Well 50	1/12/2011	Arkoma	528	22.0
GCR6 - Well 51	1/26/2011	Arkoma	216	9.0
GCR6 - Well 52	1/27/2011	Arkoma	192	8.0
GCR6 - Well 53	1/31/2011	Arkoma	120	5.0
GCR6 - Well 54	2/1/2011	Arkoma	144	6.0
GCR6 - Well 55	2/2/2011	Arkoma	120	5.0
GCR6 - Well 56	2/2/2011	Arkoma	144	6.0
GCR6 - Well 57	2/1/2011	Arkoma	192	8.0
GCR6 - Well 58	1/31/2011	Arkoma	264	11.0
GCR6 - Well 59	2/2/2011	Arkoma	240	10.0
GCR6 - Well 60	2/1/2011	Arkoma	264	11.0
GCR6 - Well 61	1/31/2011	Arkoma	288	12.0
GCR6 - Well 62	2/3/2011	Arkoma	240	10.0
GCR6 - Well 63	2/4/2011	Arkoma	216	9.0
GCR6 - Well 64	2/3/2011	Arkoma	240	10.0
GCR6 - Well 65	2/4/2011	Arkoma	216	9.0
GCR6 - Well 66	12/4/2010	Arkoma	1728	72.0
GCR6 - Well 67	1/28/2011	Arkoma	408	17.0
GCR6 - Well 68	2/7/2011	Arkoma	192	8.0
GCR6 - Well 69	2/2/2011	Arkoma	336	14.0
GCR6 - Well 70	2/13/2011	Arkoma	96	4.0
GCR6 - Well 71	2/14/2011	Arkoma	72	3.0
GCR6 - Well 72	2/12/2011	Arkoma	120	5.0
GCR6 - Well 73	1/24/2011	Arkoma	576	24.0
GCR6 - Well 74	2/12/2011	Arkoma	144	6.0
GCR6 - Well 75	2/13/2011	Arkoma	120	5.0

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR6 - Well 76	2/14/2011	Arkoma	96	4.0
GCR6 - Well 77	1/25/2011	Arkoma	576	24.0
GCR6 - Well 78	1/26/2011	Arkoma	552	23.0
GCR6 - Well 79	1/25/2011	Arkoma	576	24.0
GCR6 - Well 80	2/20/2011	Arkoma	72	3.0
GCR6 - Well 81	2/18/2011	Arkoma	120	5.0
GCR6 - Well 82	2/17/2011	Arkoma	144	6.0
GCR6 - Well 83	2/20/2011	Arkoma	72	3.0
GCR6 - Well 84	2/18/2011	Arkoma	120	5.0
GCR6 - Well 85	8/20/2010	Arkoma	4608	192.0
GCR6 - Well 86	2/23/2011	Arkoma	144	6.0
GCR6 - Well 87	2/22/2011	Arkoma	168	7.0
GCR6 - Well 88	2/21/2011	Arkoma	192	8.0
GCR6 - Well 89	2/23/2011	Arkoma	144	6.0
GCR6 - Well 90	2/22/2011	Arkoma	168	7.0
GCR6 - Well 91	2/21/2011	Arkoma	192	8.0
GCR6 - Well 92	2/24/2011	Arkoma	144	6.0
GCR6 - Well 93	2/24/2011	Arkoma	144	6.0
GCR6 - Well 94	2/24/2011	Arkoma	144	6.0
GCR6 - Well 95	2/23/2011	Arkoma	168	7.0
GCR6 - Well 96	2/22/2011	Arkoma	192	8.0
GCR6 - Well 97	2/21/2011	Arkoma	240	10.0
GCR6 - Well 98	2/22/2011	Arkoma	216	9.0
GCR6 - Well 99	2/25/2011	Arkoma	168	7.0
GCR6 - Well 100	2/26/2011	Arkoma	144	6.0
GCR6 - Well 101	2/23/2011	Arkoma	240	10.0
GCR6 - Well 102	2/24/2011	Arkoma	216	9.0
GCR6 - Well 103	3/2/2011	Arkoma	120	5.0
GCR6 - Well 104	3/7/2011	Arkoma	48	2.0
GCR6 - Well 105	3/5/2011	Arkoma	96	4.0
GCR6 - Well 106	3/5/2011	Arkoma	96	4.0
GCR6 - Well 107	3/6/2011	Arkoma	96	4.0
GCR6 - Well 108	3/11/2011	Arkoma	120	5.0
GCR6 - Well 109	3/9/2011	Arkoma	192	8.0

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR6 - Well 110	3/9/2011	Arkoma	192	8.0
GCR6 - Well 111	3/10/2011	Arkoma	168	7.0
GCR6 - Well 112	3/10/2011	Arkoma	168	7.0
GCR6 - Well 113	3/11/2011	Arkoma	144	6.0
GCR6 - Well 114	3/4/2011	Arkoma	312	13.0
GCR6 - Well 115	3/12/2011	Arkoma	144	6.0
GCR6 - Well 116	3/11/2011	Arkoma	168	7.0
GCR6 - Well 117	3/10/2011	Arkoma	192	8.0
GCR6 - Well 118	3/14/2011	Arkoma	120	5.0
GCR6 - Well 119	3/15/2011	Arkoma	96	4.0
GCR6 - Well 120	3/11/2011	Arkoma	216	9.0
GCR6 - Well 121	3/12/2011	Arkoma	216	9.0
GCR6 - Well 122	3/4/2011	Arkoma	408	17.0
GCR6 - Well 123	1/28/2011	Arkoma	1272	53.0
GCR6 - Well 124	1/29/2011	Arkoma	1248	52.0
GCR6 - Well 125	1/29/2011	Arkoma	1248	52.0
GCR6 - Well 126	3/5/2011	Arkoma	408	17.0
GCR6 - Well 127	3/16/2011	Arkoma	168	7.0
GCR6 - Well 128	3/15/2011	Arkoma	192	8.0
GCR6 - Well 129	3/20/2011	Arkoma	72	3.0
GCR6 - Well 130	3/11/2011	Arkoma	288	12.0
GCR6 - Well 131	3/17/2011	Arkoma	168	7.0
GCR6 - Well 132	3/18/2011	Arkoma	144	6.0
GCR6 - Well 133	3/17/2011	Arkoma	192	8.0
GCR6 - Well 134	3/18/2011	Arkoma	168	7.0
GCR6 - Well 135	3/19/2011	Arkoma	144	6.0
GCR6 - Well 136	3/7/2011	Arkoma	480	20.0
GCR6 - Well 137	3/8/2011	Arkoma	456	19.0
GCR6 - Well 138	3/7/2011	Arkoma	480	20.0
GCR6 - Well 139	3/7/2011	Arkoma	480	20.0
GCR6 - Well 140	3/6/2011	Arkoma	504	21.0
GCR6 - Well 141	3/25/2011	Arkoma	144	6.0
GCR6 - Well 142	3/26/2011	Arkoma	120	5.0
GCR6 - Well 143	3/26/2011	Arkoma	120	5.0

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Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR6 - Well 144	3/26/2011	Arkoma	120	5.0
GCR6 - Well 145	3/27/2011	Arkoma	96	4.0
GCR6 - Well 146	3/24/2011	Arkoma	168	7.0
GCR6 - Well 147	3/25/2011	Arkoma	144	6.0
GCR6 - Well 148	3/22/2011	Arkoma	216	9.0
GCR6 - Well 149	3/27/2011	Arkoma	120	5.0
GCR6 - Well 150	3/28/2011	Arkoma	96	4.0
GCR6 - Well 151	3/23/2011	Arkoma	264	11.0
GCR6 - Well 152	3/24/2011	Arkoma	240	10.0
GCR6 - Well 153	4/2/2011	Arkoma	96	4.0
GCR6 - Well 154	4/2/2011	Arkoma	96	4.0
GCR6 - Well 155	4/1/2011	Arkoma	144	6.0
GCR6 - Well 156	4/4/2011	Arkoma	72	3.0
GCR6 - Well 157	4/1/2011	Arkoma	144	6.0
GCR6 - Well 158	3/31/2011	Arkoma	168	7.0
GCR6 - Well 159	4/1/2011	Arkoma	144	6.0
GCR6 - Well 160	3/27/2011	Arkoma	288	12.0
GCR6 - Well 161	3/29/2011	Arkoma	240	10.0
GCR6 - Well 162	3/28/2011	Arkoma	264	11.0
GCR6 - Well 163	3/31/2011	Arkoma	192	8.0
GCR6 - Well 164	4/5/2011	Arkoma	72	3.0
GCR6 - Well 165	4/4/2011	Arkoma	96	4.0
GCR6 - Well 166	3/31/2011	Arkoma	192	8.0
GCR6 - Well 167	4/5/2011	Arkoma	168	7.0
GCR6 - Well 168	4/5/2011	Arkoma	168	7.0
GCR6 - Well 169	4/4/2011	Arkoma	192	8.0
GCR6 - Well 170	4/9/2011	Arkoma	120	5.0
GCR6 - Well 171	4/10/2011	Arkoma	120	5.0
GCR6 - Well 172	4/9/2011	Arkoma	144	6.0
GCR6 - Well 173	4/11/2011	Arkoma	96	4.0
GCR6 - Well 174	4/9/2011	Arkoma	144	6.0
GCR6 - Well 175	4/10/2011	Arkoma	120	5.0
GCR6 - Well 176	4/11/2011	Arkoma	96	4.0
GCR6 - Well 177	4/10/2011	Arkoma	144	6.0

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR6 - Well 178	4/11/2011	Arkoma	120	5.0
GCR6 - Well 179	4/11/2011	Arkoma	120	5.0
GCR6 - Well 180	4/12/2011	Arkoma	120	5.0
GCR6 - Well 181	3/20/2011	Arkoma	696	29.0
GCR6 - Well 182	4/13/2011	Arkoma	144	6.0
GCR6 - Well 183	4/12/2011	Arkoma	168	7.0
GCR6 - Well 184	4/12/2011	Arkoma	192	8.0
GCR6 - Well 185	4/16/2011	Arkoma	96	4.0
GCR6 - Well 186	4/13/2011	Arkoma	192	8.0
GCR6 - Well 187	4/13/2011	Arkoma	192	8.0
GCR6 - Well 188	4/16/2011	Arkoma	168	7.0
GCR6 - Well 189	4/13/2011	Arkoma	312	13.0
GCR6 - Well 190	4/14/2011	Arkoma	288	12.0
GCR6 - Well 191	4/13/2011	Arkoma	312	13.0
GCR6 - Well 192	4/17/2011	Arkoma	240	10.0
GCR6 - Well 193	4/18/2011	Arkoma	216	9.0
GCR6 - Well 194	4/17/2011	Arkoma	240	10.0
GCR6 - Well 195	4/22/2011	Arkoma	144	6.0
GCR6 - Well 196	4/23/2011	Arkoma	144	6.0
GCR6 - Well 197	4/25/2011	Arkoma	96	4.0
GCR6 - Well 198	4/23/2011	Arkoma	144	6.0
GCR6 - Well 199	4/26/2011	Arkoma	96	4.0
GCR6 - Well 200	4/25/2011	Arkoma	120	5.0
GCR6 - Well 201	4/25/2011	Arkoma	144	6.0
GCR6 - Well 202	4/25/2011	Arkoma	144	6.0
GCR6 - Well 203	4/22/2011	Arkoma	264	11.0
GCR6 - Well 204	4/22/2011	Arkoma	264	11.0
GCR6 - Well 205	4/27/2011	Arkoma	192	8.0
GCR6 - Well 206	4/29/2011	Arkoma	168	7.0
GCR6 - Well 207	4/29/2011	Arkoma	168	7.0
GCR6 - Well 208	4/27/2011	Arkoma	216	9.0
GCR6 - Well 209	4/27/2011	Arkoma	216	9.0
GCR6 - Well 210	5/2/2011	Arkoma	192	8.0
GCR6 - Well 211	5/3/2011	Arkoma	168	7.0

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR6 - Well 212	5/2/2011	Arkoma	192	8.0
GCR6 - Well 213	5/5/2011	Arkoma	168	7.0
GCR6 - Well 214	5/6/2011	Arkoma	144	6.0
GCR6 - Well 215	5/6/2011	Arkoma	144	6.0
GCR6 - Well 216	5/6/2011	Arkoma	144	6.0
GCR6 - Well 217	5/7/2011	Arkoma	144	6.0
GCR6 - Well 218	5/8/2011	Arkoma	120	5.0
GCR6 - Well 219	5/6/2011	Arkoma	168	7.0
GCR6 - Well 220	5/4/2011	Arkoma	216	9.0
GCR6 - Well 221	5/5/2011	Arkoma	192	8.0
GCR6 - Well 222	5/5/2011	Arkoma	192	8.0
GCR6 - Well 223	5/9/2011	Arkoma	144	6.0
GCR6 - Well 224	5/10/2011	Arkoma	120	5.0
GCR6 - Well 225	5/13/2011	Arkoma	144	6.0
GCR6 - Well 226	5/17/2011	Arkoma	72	3.0
GCR6 - Well 227	5/13/2011	Arkoma	168	7.0
GCR6 - Well 228	5/14/2011	Arkoma	144	6.0
GCR6 - Well 229	4/15/2011	Arkoma	840	35.0
GCR6 - Well 230	4/15/2011	Arkoma	840	35.0
GCR6 - Well 231	5/18/2011	Arkoma	72	3.0
GCR6 - Well 232	5/18/2011	Arkoma	72	3.0
GCR6 - Well 233	5/16/2011	Arkoma	120	5.0
GCR6 - Well 234	5/17/2011	Arkoma	96	4.0
GCR6 - Well 235	5/16/2011	Arkoma	168	7.0
GCR6 - Well 236	5/17/2011	Arkoma	144	6.0
GCR6 - Well 237	5/16/2011	Arkoma	168	7.0
GCR6 - Well 238	5/17/2011	Arkoma	168	7.0
GCR6 - Well 239	5/19/2011	Arkoma	144	6.0
GCR6 - Well 240	5/19/2011	Arkoma	144	6.0
GCR6 - Well 241	5/22/2011	Arkoma	120	5.0
GCR6 - Well 242	5/23/2011	Arkoma	96	4.0
GCR6 - Well 243	5/22/2011	Arkoma	120	5.0
GCR6 - Well 244	5/24/2011	Arkoma	72	3.0
GCR6 - Well 245	5/23/2011	Arkoma	96	4.0

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR6 - Well 246	5/24/2011	Arkoma	72	3.0
GCR6 - Well 247	5/2/2011	Arkoma	624	26.0
GCR6 - Well 248	5/9/2011	Arkoma	528	22.0
GCR6 - Well 249	5/25/2011	Arkoma	192	8.0
GCR6 - Well 250	5/26/2011	Arkoma	168	7.0
GCR6 - Well 251	5/25/2011	Arkoma	192	8.0
GCR6 - Well 252	5/25/2011	Arkoma	192	8.0
GCR6 - Well 253	5/26/2011	Arkoma	168	7.0
GCR6 - Well 254	5/25/2011	Arkoma	192	8.0
GCR6 - Well 255	5/27/2011	Arkoma	168	7.0
GCR6 - Well 256	5/27/2011	Arkoma	192	8.0
GCR6 - Well 257	5/28/2011	Arkoma	168	7.0
GCR6 - Well 258	5/27/2011	Arkoma	192	8.0
GCR6 - Well 259	5/28/2011	Arkoma	168	7.0
GCR6 - Well 260	6/1/2011	Arkoma	168	7.0
GCR6 - Well 261	5/31/2011	Arkoma	192	8.0
GCR6 - Well 262	6/2/2011	Arkoma	144	6.0
GCR6 - Well 263	6/1/2011	Arkoma	168	7.0
GCR6 - Well 264	5/31/2011	Arkoma	192	8.0
GCR6 - Well 265	6/3/2011	Arkoma	144	6.0
GCR6 - Well 266	6/2/2011	Arkoma	168	7.0
GCR6 - Well 267	6/2/2011	Arkoma	168	7.0
GCR6 - Well 268	6/1/2011	Arkoma	192	8.0
GCR6 - Well 269	6/3/2011	Arkoma	144	6.0
GCR6 - Well 270	6/3/2011	Arkoma	144	6.0
GCR6 - Well 271	6/7/2011	Arkoma	72	3.0
GCR6 - Well 272	6/6/2011	Arkoma	96	4.0
GCR6 - Well 273	6/6/2011	Arkoma	96	4.0
GCR6 - Well 274	6/6/2011	Arkoma	96	4.0
GCR6 - Well 275	6/6/2011	Arkoma	120	5.0
GCR6 - Well 276	6/7/2011	Arkoma	96	4.0
GCR6 - Well 277	1/26/2011	Arkoma	3336	139.0
GCR6 - Well 278	6/6/2011	Arkoma	192	8.0
GCR6 - Well 279	6/7/2011	Arkoma	168	7.0

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR6 - Well 280	6/5/2011	Arkoma	240	10.0
GCR6 - Well 281	6/4/2011	Arkoma	264	11.0
GCR6 - Well 282	6/5/2011	Arkoma	240	10.0
GCR6 - Well 283	6/4/2011	Arkoma	264	11.0
GCR6 - Well 284	6/13/2011	Arkoma	72	3.0
GCR6 - Well 285	6/15/2011	Arkoma	168	7.0
GCR6 - Well 286	6/14/2011	Arkoma	192	8.0
GCR6 - Well 287	6/20/2011	Arkoma	72	3.0
GCR6 - Well 288	3/28/2011	Arkoma	2088	87.0
GCR6 - Well 289	6/16/2011	Arkoma	168	7.0
GCR6 - Well 290	6/17/2011	Arkoma	144	6.0
GCR6 - Well 291	6/15/2011	Arkoma	192	8.0
GCR6 - Well 292	6/16/2011	Arkoma	168	7.0
GCR6 - Well 293	6/20/2011	Arkoma	96	4.0
GCR6 - Well 294	6/24/2011	Arkoma	96	4.0
GCR6 - Well 295	6/25/2011	Arkoma	72	3.0
GCR6 - Well 296	6/27/2011	Arkoma	120	5.0
GCR6 - Well 297	6/27/2011	Arkoma	120	5.0
GCR6 - Well 298	6/28/2011	Arkoma	96	4.0
GCR6 - Well 299	6/24/2011	Arkoma	192	8.0
GCR6 - Well 300	6/23/2011	Arkoma	216	9.0
GCR6 - Well 301	6/28/2011	Arkoma	96	4.0
GCR6 - Well 302	6/22/2011	Arkoma	264	11.0
GCR6 - Well 303	6/19/2011	Arkoma	336	14.0
GCR6 - Well 304	6/14/2011	Arkoma	456	19.0
GCR6 - Well 305	7/1/2011	Arkoma	48	2.0
GCR6 - Well 306	6/27/2011	Arkoma	216	9.0
GCR6 - Well 307	6/28/2011	Arkoma	192	8.0
GCR6 - Well 308	6/27/2011	Arkoma	216	9.0
GCR6 - Well 309	6/28/2011	Arkoma	192	8.0
GCR6 - Well 310	7/6/2011	Arkoma	72	3.0
GCR6 - Well 311	7/6/2011	Arkoma	72	3.0
GCR6 - Well 312	7/7/2011	Arkoma	48	2.0
GCR6 - Well 313	7/6/2011	Arkoma	168	7.0

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR6 - Well 314	7/8/2011	Arkoma	120	5.0
GCR6 - Well 315	7/6/2011	Arkoma	168	7.0
GCR6 - Well 316	7/7/2011	Arkoma	144	6.0
GCR6 - Well 317	7/8/2011	Arkoma	120	5.0
GCR6 - Well 318	7/7/2011	Arkoma	144	6.0
GCR6 - Well 319	6/25/2011	Arkoma	456	19.0
GCR6 - Well 320	7/8/2011	Arkoma	144	6.0
GCR6 - Well 321	7/11/2011	Arkoma	96	4.0
GCR6 - Well 322	7/16/2011	Arkoma	120	5.0
GCR6 - Well 323	7/15/2011	Arkoma	144	6.0
GCR6 - Well 324	7/14/2011	Arkoma	168	7.0
GCR6 - Well 325	7/20/2011	Arkoma	72	3.0
GCR6 - Well 326	7/27/2011	Arkoma	72	3.0
GCR6 - Well 327	7/27/2011	Arkoma	96	4.0
GCR6 - Well 328	7/22/2011	Arkoma	288	12.0
GCR6 - Well 329	7/23/2011	Arkoma	264	11.0
GCR6 - Well 330	7/21/2011	Arkoma	312	13.0
GCR6 - Well 331	7/25/2011	Arkoma	240	10.0
GCR6 - Well 332	8/1/2011	Arkoma	96	4.0
GCR6 - Well 333	8/2/2011	Arkoma	72	3.0
GCR6 - Well 334	8/1/2011	Arkoma	96	4.0
GCR6 - Well 335	8/2/2011	Arkoma	96	4.0
GCR6 - Well 336	7/30/2011	Arkoma	192	8.0
GCR6 - Well 337	7/31/2011	Arkoma	168	7.0
GCR6 - Well 338	7/31/2011	Arkoma	168	7.0
GCR6 - Well 339	7/29/2011	Arkoma	216	9.0
GCR6 - Well 340	7/30/2011	Arkoma	216	9.0
GCR6 - Well 341	8/6/2011	Arkoma	168	7.0
GCR6 - Well 342	8/4/2011	Arkoma	216	9.0
GCR6 - Well 343	8/5/2011	Arkoma	192	8.0
GCR6 - Well 344	8/6/2011	Arkoma	168	7.0
GCR6 - Well 345	8/5/2011	Arkoma	192	8.0
GCR6 - Well 346	8/8/2011	Arkoma	120	5.0
GCR6 - Well 347	8/9/2011	Arkoma	96	4.0

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR6 - Well 348	8/8/2011	Arkoma	120	5.0
GCR6 - Well 349	8/8/2011	Arkoma	168	7.0
GCR6 - Well 350	8/5/2011	Arkoma	240	10.0
GCR6 - Well 351	8/5/2011	Arkoma	240	10.0
GCR6 - Well 352	8/9/2011	Arkoma	168	7.0
GCR6 - Well 353	8/14/2011	Arkoma	72	3.0
GCR6 - Well 354	8/13/2011	Arkoma	96	4.0
GCR6 - Well 355	8/14/2011	Arkoma	96	4.0
GCR6 - Well 356	8/15/2011	Arkoma	72	3.0
GCR6 - Well 357	8/13/2011	Arkoma	120	5.0
GCR6 - Well 358	8/13/2011	Arkoma	144	6.0
GCR6 - Well 359	8/4/2011	Arkoma	384	16.0
GCR6 - Well 360	7/28/2011	Arkoma	552	23.0
GCR6 - Well 361	7/28/2011	Arkoma	552	23.0
GCR6 - Well 362	7/31/2011	Arkoma	480	20.0
GCR6 - Well 363	8/17/2011	Arkoma	72	3.0
GCR6 - Well 364	8/3/2011	Arkoma	408	17.0
GCR6 - Well 365	8/17/2011	Arkoma	168	7.0
GCR6 - Well 366	8/18/2011	Arkoma	144	6.0
GCR6 - Well 367	8/17/2011	Arkoma	168	7.0
GCR6 - Well 368	8/16/2011	Arkoma	192	8.0
GCR6 - Well 369	8/16/2011	Arkoma	192	8.0
GCR6 - Well 370	8/22/2011	Arkoma	96	4.0
GCR6 - Well 371	8/23/2011	Arkoma	72	3.0
GCR6 - Well 372	8/22/2011	Arkoma	96	4.0
GCR6 - Well 373	8/24/2011	Arkoma	72	3.0
GCR6 - Well 374	8/23/2011	Arkoma	96	4.0
GCR6 - Well 375	8/23/2011	Arkoma	120	5.0
GCR6 - Well 376	8/22/2011	Arkoma	144	6.0
GCR6 - Well 377	8/21/2011	Arkoma	168	7.0
GCR6 - Well 378	8/20/2011	Arkoma	192	8.0
GCR6 - Well 379	8/8/2011	Arkoma	504	21.0
GCR6 - Well 380	8/10/2011	Arkoma	456	19.0
GCR6 - Well 381	8/11/2011	Arkoma	432	18.0

URS

Well Number	Date Well Completed	Basin	Flowback Duration (Hours)	Duration Days
GCR6 - Well 382	8/25/2011	Arkoma	216	9.0
GCR6 - Well 383	8/25/2011	Arkoma	216	9.0
GCR6 - Well 384	8/25/2011	Arkoma	216	9.0
GCR6 - Well 385	8/26/2011	Arkoma	192	8.0
GCR6 - Well 386	9/1/2011	Arkoma	144	6.0
GCR6 - Well 387	8/31/2011	Arkoma	168	7.0
GCR6 - Well 388	9/1/2011	Arkoma	144	6.0
GCR6 - Well 389	8/31/2011	Arkoma	168	7.0
GCR6 - Well 390	8/29/2011	Arkoma	240	10.0
GCR6 - Well 391	8/30/2011	Arkoma	216	9.0
GCR6 - Well 392	8/30/2011	Arkoma	216	9.0
GCR6 - Well 393	8/30/2011	Arkoma	216	9.0
GCR6 - Well 394	8/29/2011	Arkoma	240	10.0
GCR6 - Well 395	8/29/2011	Arkoma	264	11.0
GCR6 - Well 396	1/2/2011	East Texas	386	16.1
GCR6 - Well 397	1/28/2011	East Texas	451	18.8
GCR6 - Well 398	2/24/2011	East Texas	402	16.8
GCR6 - Well 399	4/11/2011	East Texas		

Appendix B

Mismeasuring Methane

Estimating Greenhouse Gas Emissions from Upstream Natural Gas Development

PRIVATE REPORT®

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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.

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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 (CO_2), methane that leaks or is purposely vented into the atmosphere is more harmful than the CO_2 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

IHS CERA

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 (CO_2) 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 CO_2, with a global warming potential (GWP) estimated at 25 times that of CO_2.*

Methane and CO_2 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 CO_2 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 CO_2 in its second scientific assessment report published in 1995 to 25 times that of CO_2 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 CO_2, 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 fracced 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 CO_2 or nitrogen that were injected during fraccing 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 CO_2 or nitrogen that were used during the fraccing 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 fracced 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 CO_2, 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 CO_2 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 CO_2 is removed from gas at processing plants than is released in the field (primarily) during flaring.

METHANE AND CO_2 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 CO_2-equivalent ($mtCO_2e$) to 198 $mtCO_2e$.*

*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, CO_2 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.

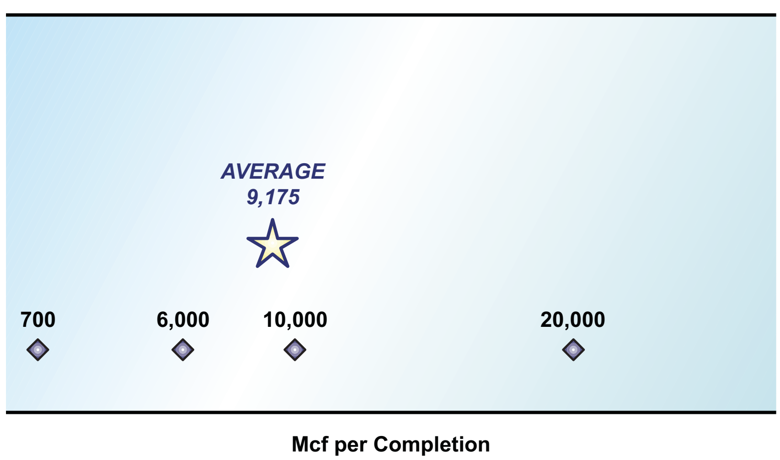
- "The final Natural Gas STAR presentation with adequate data to determine an average emission rate also presented the total flowback and total completions and recompletions. Because of the high variability and uncertainty associated with different completion flowbacks in the gas industry, this was **rounded 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 $mtCO_2e$ 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 fraccing fluids that flow back from these wells and the methane that accompanies the fraccing 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 CO_2, 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. ■

Appendix C

EPA seriously overstates well emissions

Incorrect estimates have critical policy implications

EPA's 2011 recalculation of methane, volatile organic compound (VOC) and hazardous air pollutant (HAP) emission estimates from natural gas wells are overstated by orders of magnitude and are undermining other research work and policy consideration.

Background

In 2010, EPA issued a background technical support document titled, "Greenhouse gas emissions reporting from the petroleum and natural gas industry." In the report, EPA altered the methodology it had previously used to estimate methane emissions from natural gas production.

Before 2010, EPA estimated 0.02 metric tons of methane were emitted per well completion. In 2010, EPA made dramatic changes to its estimates. The new estimates hold that conventional natural gas wells emit 0.71 metric tons of methane, and shale gas wells emit 177 metric tons of methane per well completion. As a result of these new estimates, EPA adjusted prior-year U.S. greenhouse gas emission reports retroactively as far back as 1990 to reflect the new estimates.

> "EPA's faulty estimates have led researchers, financial analysts and other governmental bodies to rely on inaccurate statistics in a number of research reports and in policy consideration."

Problem

A report exploring the inaccuracies in EPA's methodology in determining methane emissions from natural gas production was released in August 2011. IHS CERA, a highly respected research firm with specific expertise in the oil and natural gas production sector, released a report titled, "Mismeasuring Methane: Estimating greenhouse gas emissions from upstream natural gas development." In the analysis, IHS CERA points out specific flaws EPA made in its analysis, including:

- The misuse and inaccurate application of Natural Gas STAR program data collected from a small number of wells to assume industry-wide emission rates — based on the erroneous assumption that methane reported as captured through "green completions" would otherwise be vented to the atmosphere when a green completion is not performed.

- EPA's flawed rounding of data points to the nearest hundredth, thousandth, and even ten thousandth Mcf to overcome the "high variability and uncertainty" in the industry — masking a lack of consistent and reliable data that would undermine the EPA conclusions.

- Developing an assumption that producers in Texas, New Mexico and Oklahoma vent to the atmosphere during flowback, rather than commonly flaring or capturing emissions, simply because those states do not mandate flaring or recovery.

As a follow-on to the IHS-CERA study, Devon conducted its own investigation that revealed that EPA emission estimates were 1400 percent greater than Devon's actual emissions. Subsequently, URS Corporation conducted a survey that revealed EPA emission estimates as much as 1200 percent greater than emissions of the seven companies that participated in the study.

The work by URS Corporation in November 2011 involved gathering and analyzing U.S. well data completed in more than 10 different basins across the country. Using an EPA-endorsed flow equation with assumptions that provide high estimates, URS found that methane emissions among the seven companies represent less than eight percent of the EPA estimates. This means actual production-related emissions of associated volatile organic compounds and hazardous air pollutants in the gas stream are also less than eight percent of what the EPA believes.

EPA's faulty estimates have led researchers, financial analysts and other governmental bodies to rely on inaccurate statistics in a number of research reports and in policy consideration. For example, Dr. Robert Howarth of Cornell University led a team that released a study this past spring questioning whether natural gas is truly a cleaner fuel than coal. Certainly Dr. Howarth's study included several inaccurate assumptions of his own making, but a key basis for his review lies in the overestimation of methane emissions developed by EPA.

The Cornell study and EPA's methane emission estimates are also finding voice in other government studies. The U.S. Department of Energy SEAB Natural Gas Subcommittee report even mentions the "pessimistic conclusion about the greenhouse gas footprint of shale gas production and use."

Perhaps most important, critical policy initiatives and discussions are being based on EPA's flawed estimates. Currently the proposed new source performance standards for the oil and natural gas industry are founded in part on what are now seen to be seriously inflated estimates of VOCs, HAPs and methane emissions as calculated by EPA. In addition, those concerned about broad global climate change policy see the revised EPA methane emission numbers as calling into question the clean advantage of natural gas.

Finally, the EPA emission estimates fly in the face of sound business and economic principles. Producers have every incentive to capture as much valuable methane as possible, as early as possible, in the well completion and production process. That is a key driver in the use of advanced early production processes (AEPP) that ensure early methane capture, even during initial well flowback (with the environmental benefits leading to the term "green completions"). This is important because if EPA's estimates were true, Devon would have lost more than $305 million to the atmosphere in a single year. No business would tolerate this type of waste.

Solution
To prevent further unintended consequences by use of seriously flawed EPA emission estimates, EPA should return to its time-tested methodology and previous estimates.

11-30-11 / Contact: Darren Smith 405 228 8584
Bill Whitsitt 405 552 3556

Appendix D

Testimony of Darren Smith, Environmental Manager, Devon Energy Corporation

Before the EPW Subcommittee on Clean Air and Nuclear Safety

Washington, D.C. June 19th, 2012.

Dear Mr. Chairman and members of the Subcommittee. Thank you for the opportunity to be here today.

My name is Darren Smith, and I am the Environmental Manager for Devon Energy.

Devon is a leading independent oil and natural gas company focused onshore in the United States and Canada. The company's portfolio of oil and gas properties provides stable, environmentally responsible production. We work hard to conduct operations in an environmentally responsible way, reducing impact on land, water and air. This is good for the environment and is good for business. It is important to note that Devon supports reasonable regulation of the industry; however, we oppose inappropriate regulations that are based on unsound science.

My testimony this morning will describe EPA's misperception of initial production from gas wells. I will describe how this misperception has led to a drastic overestimate of methane emissions from hydraulically fractured natural gas wells. This overestimate has allowed EPA to justify the promulgation of new air standards for the natural gas industry. More important, we continue to see new policy research being based on a foundation of this bad data - guaranteeing that the wrong conclusions are reached.

It was when researchers from Cornell University released their "natural gas is dirtier than coal study" that Devon first became aware that EPA had dramatically changed its emissions estimate for hydraulically fractured gas wells. EPA now asserts, and has reported to the United Nations Intergovernmental Panel on Climate Change, that each unconventional gas well emits over 9 million standard cubic feet of natural gas to the atmosphere and has done so since 1990.

Devon became suspicious of EPA's new estimate because if true, it would mean that Devon alone wastes over 40 million dollars of natural gas to the atmosphere annually. Clearly, a successful company like Devon could not tolerate this level of waste.

When we investigated the basis of the estimate change we learned that EPA staff had used industry data reported to it under the voluntary EPA Natural Gas Star Program to generate the new factor. The data used came from only 3 companies.

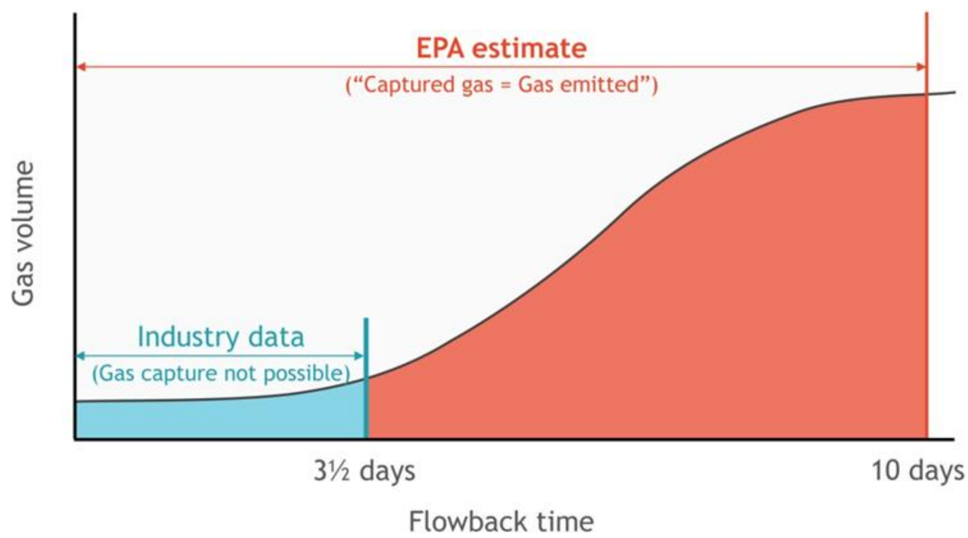
This finding represents the most significant flaw in EPA's method. Simply put, the Natural Gas Star Data represents gas captured, not gas emitted. Moreover, the data reported into the Natural Gas Star program was never intended to represent emissions.

Devon has informed EPA of this error numerous times. We have brought actual data from Devon's operation and met face to face, we have supplied comments and data from a broader set of Oil and Gas Operators to the oil and gas rule docket, we have followed up by email and telephone, and we have supplied a report from IHS CERA confirming our findings. The US Chamber of Commerce has petitioned for a correction under the Data Quality Act.

Despite all of this, EPA has failed to acknowledge its mistake much less correct it.

I would now like to turn to the graphic contained in your copy of my testimony. It will help illustrate EPA's misconception and how it has resulted in a dramatic overestimate of emissions from our industry.

Well Emissions: Actual vs. Perceived by EPA



EPA's fundamental misperception of initial gas production from natural gas wells leads to dramatic overestimates of methane emissions.

First I want to draw your attention to the curve. After a well is hydraulically fractured, it undergoes what is called flowback. In simple terms, Flowback is necessary to remove water from the well so it can produce gas.

The left side of the curve represents the beginning of flowback where water production is highest and gas production is lowest. Progressing right - as water is removed from the well, gas production increases until at the far right side, gas production reaches its maximum rate and levels off.

Now, EPA believes that the period of flowback is up to 10 days because that is what has been reported to the Natural Gas Star program. In Natural Gas Star, Operators report the volume of gas that they capture while operating specialized capture equipment. Since gas is being captured and not wasted it is not uncommon to operate this capture equipment for 10 days or more. Remember Natural Gas Star is for gas captured not gas emitted.

10 days of gas capture is on the far right side of the curve and equates to 9 million cubic feet according to how EPA averaged the Natural Gas Star data.

This contrasts significantly with the scenario where gas cannot be captured from the flowback stream – the blue shaded area.

Actual data from 8 operators has demonstrated that flowback lasts on average only 3.5 days when gas capture is not possible. An operator will flow the well back only as long as needed to remove the bulk of the water – when steady gas flow is established, the well is shut off until the pipeline is laid.

Clearly, captured gas volumes reported to Natural Gas Star, from 10 day flowback periods, are significantly higher that gas volumes released from flowback over 3 and a half days.

EPA has erred by assuming that the volume of gas captured under the Natural Gas Star program is the same volume of gas that would be emitted when gas capture is not possible.

To conclude, the error must be corrected now. We have already seen its misuse to justify air quality rules for fracking. It will continue to fuel bad public policy and research that overshadows the benefits of natural gas. Studies like the recent one from the Environmental Defense Fund that used the overestimate to suggest that Natural Gas powered vehicles are no cleaner than gasoline vehicles will continue until such time as EPA revises its published emissions data. And this will take several years.

This concludes my testimony. Thank you.

Appendix E

Realistic Completion Emissions

Stakeholder Workshop on Natural Gas in the Inventory of U.S. Greenhouse Gas Emissions and Sinks

Jesse Sandlin – Devon Energy

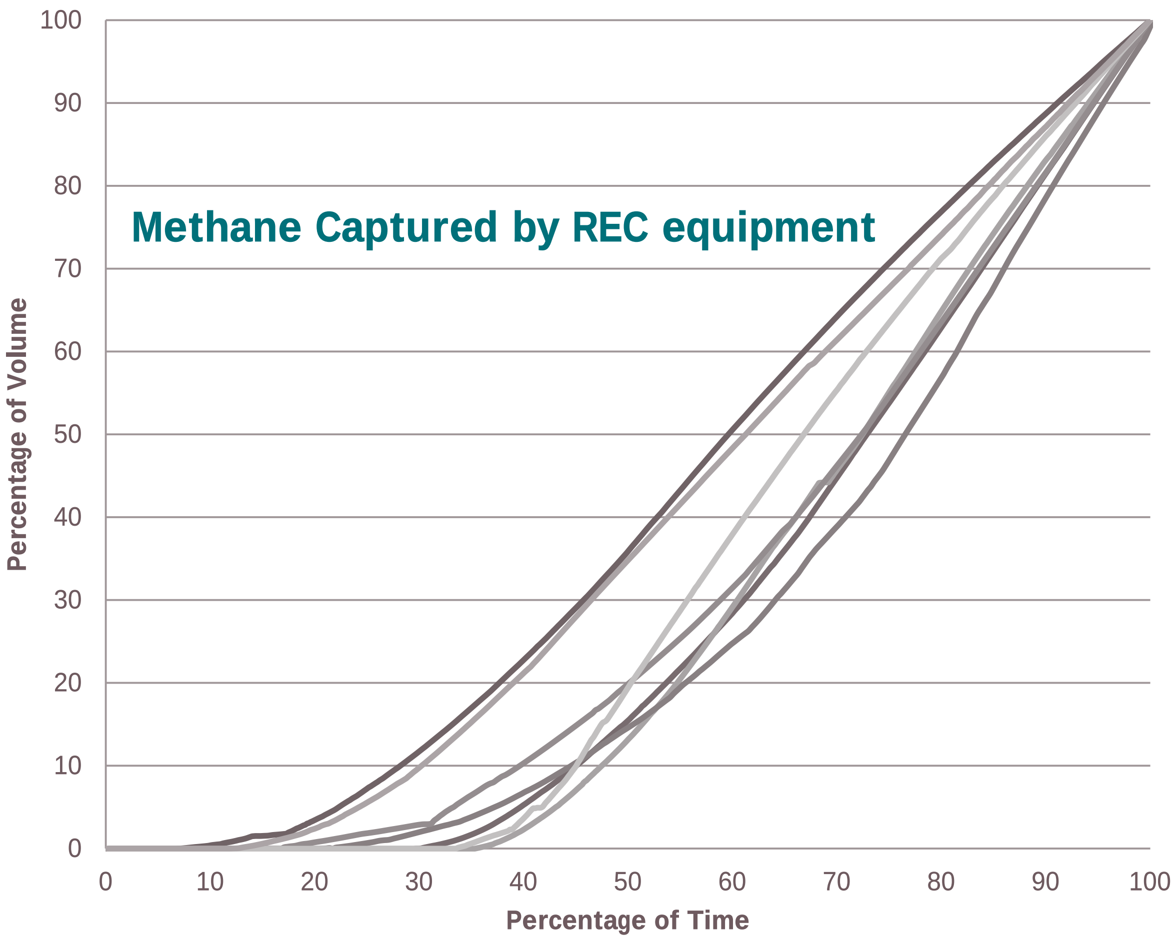
September 13, 2012

devon

Preface

- EPA's estimates that 9.175 MMCF of natural gas is released per well completion[1]
- These estimates are based on Natural Gas Star data, which measured gas **captured** by REC equipment during flowback
- Flowback with REC equipment is typically 8 to 12 days
- Without this equipment, industry averages 3.5 days of flowback[2]
- Wells typically increase methane production during flowback over time
- EPA therefore significantly overestimates methane releases from completion activities[3]

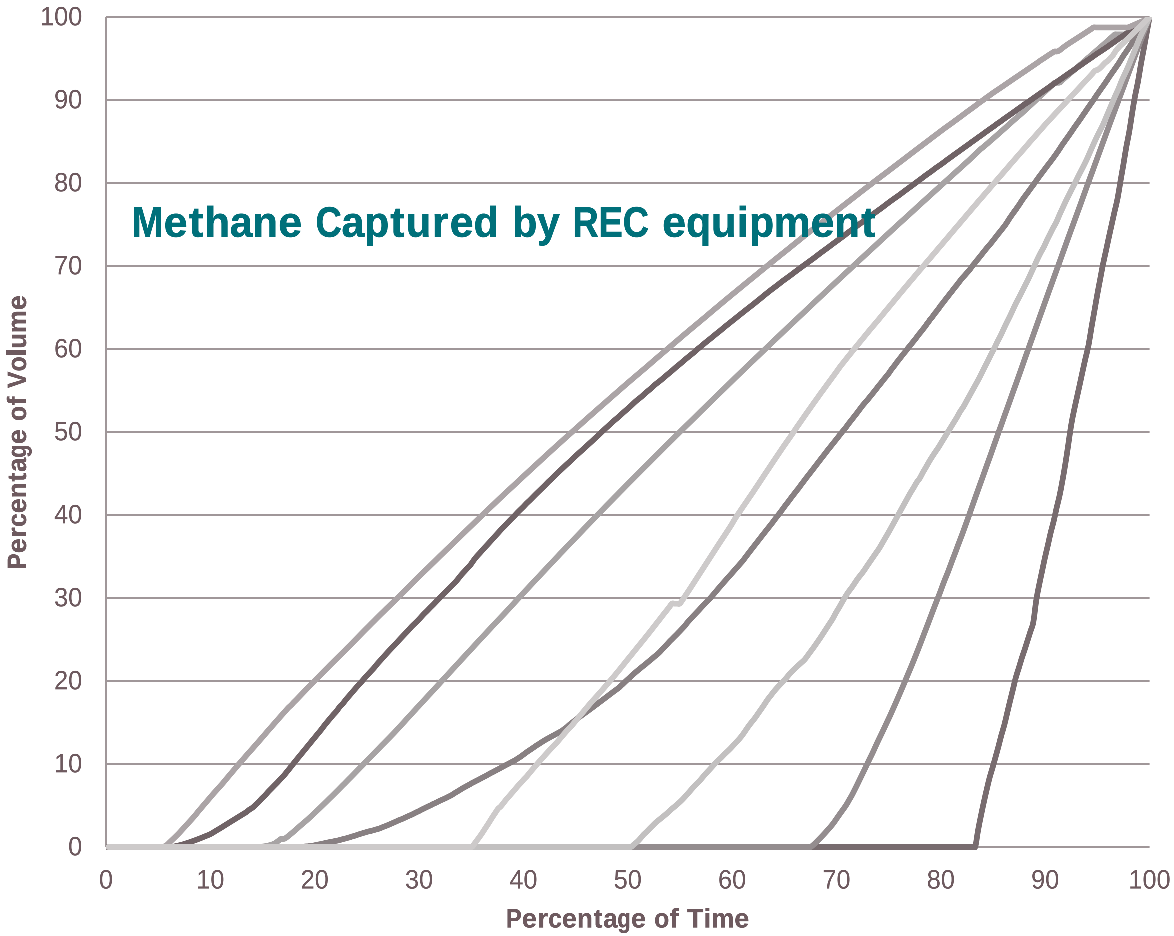
Area 1 – Cotton Valley



	MMscf		
Well	**3.5 Day**	**10 Day**	**Gas Star Reported**
No. 1	0	7.9	120.8
No. 2	0.0	0	160
No. 3	0.2	16.5	48
No. 4	1.4	22.1	99.3
No. 5	0.7	20.5	53.0
No. 6	0.0	5.7	63.8
No. 7	0.7	29.3	118.7
Avg*	**0.3**	**14.5**	**91.1**

*Average does not contain highest and lowest numbers of each set

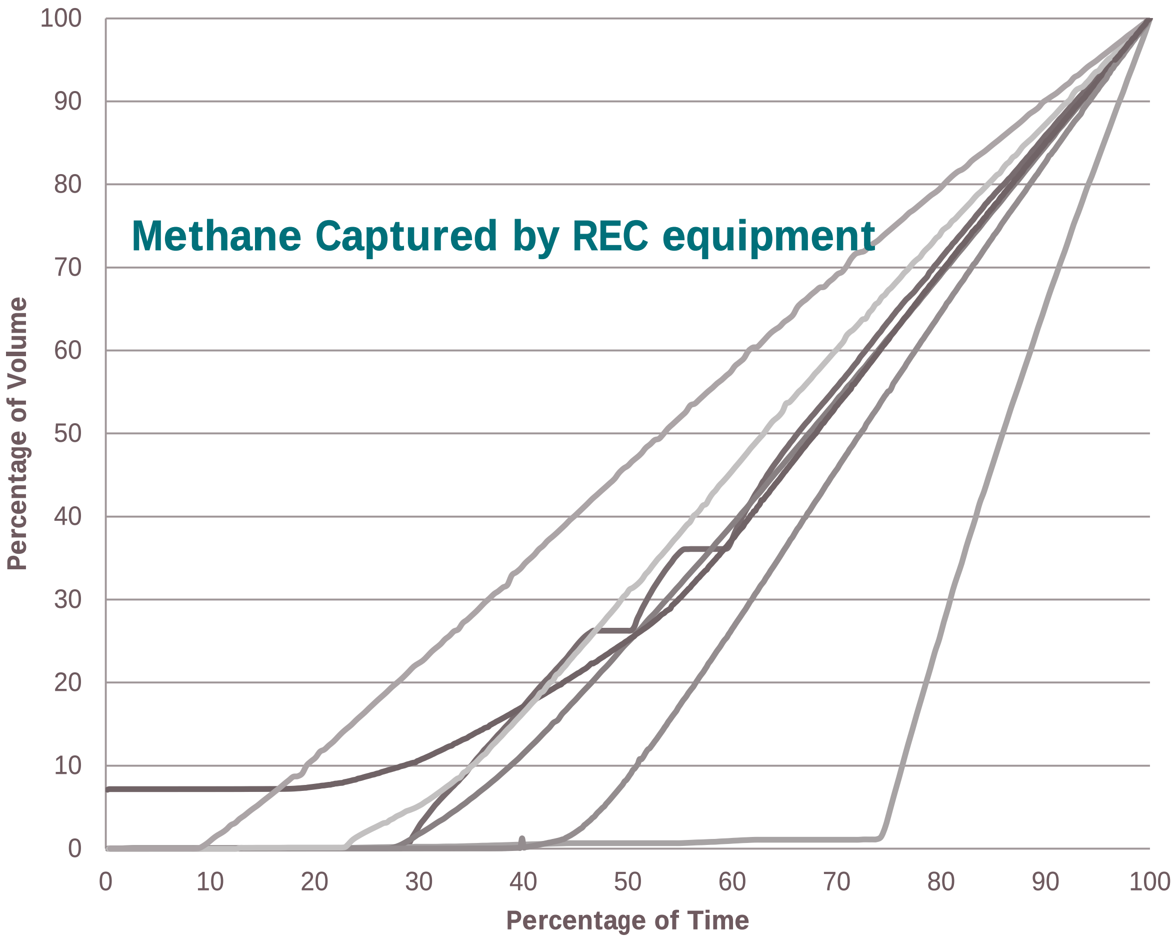
Area 2 – Western Oklahoma



	MMscf		
Well	3.5 Day	10 Day	Gas Star Reported
No. 1	0.0	0.0	0.9
No. 2	0.0	28.1	119.8
No. 3	0.0	2.1	40.8
No. 4	6.8	24.5	32.9
No. 5	0.0	0.0	27.8
No. 6	0.0	1.9	6.2
No. 7	17.8	56.7	90.9
No. 8	0.0	17.2	44.9
Avg*	**3.1**	**16.3**	**45.5**

*Average does not contain highest and lowest numbers of each set

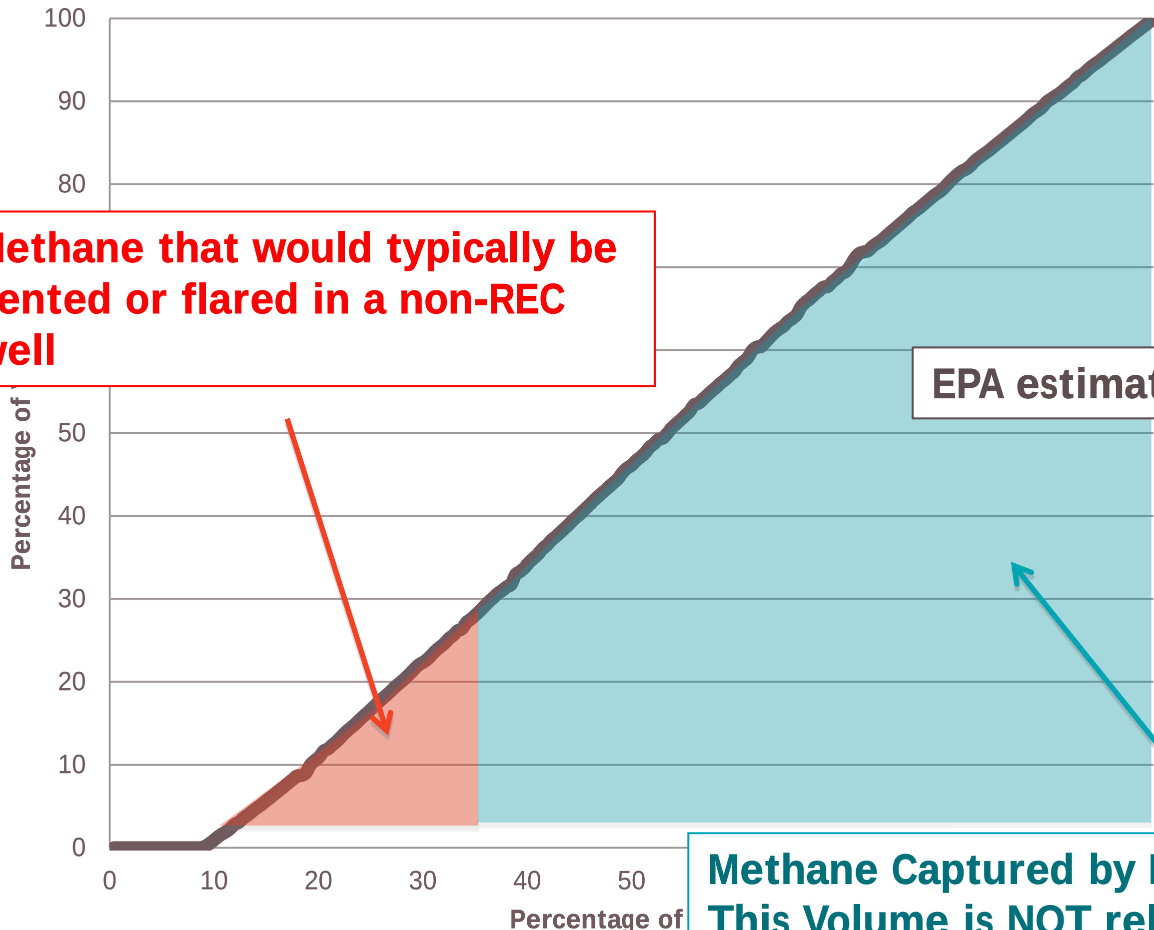
Area 3 – Barnett Shale



	MMscf		
Well	**3.5 Day**	**10 Day**	**Gas Star Reported**
No. 1	0.0	6.9	21.0
No. 2	0.0	5.3	5.3
No. 3	1.8	0.0	28.1
No. 4	4.3	8.1	59.5
No. 5	0.0	38.5	38.5
No. 6	0.6	14.3	22.0
No. 7	4.9	16.8	16.8
Avg*	**1.6**	**11.4**	**27.3**

*Average does not contain highest and lowest numbers of each set

Data mock-up



Methane that would typically be vented or flared in a non-REC well

EPA estimate includes both segments

Methane Captured by REC equipment
This Volume is NOT released at a non REC well

Thank you!

Questions?

Thank You.

References

1. EPA Greenhouse gas emission inventory sources and sinks, 2011 - http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2012-Annex-3-Additional-Source-or-Sink-Categories.pdf2.
2. URS Study, Commissioned by Devon Energy - http://anga.us/media/241555/anga-axpc%20nsps%20memo%20revised.pdf
3. See also the API/ANGA Report for additional data and evidence – not yet released

Appendix F

BY CERTIFIED MAIL
RETURN RECEIPT REQUESTED

New York Attorney General Eric T. Schneiderman
Connecticut Attorney General George Jepsen
Delaware Attorney General Joseph R. Biden, II
Maryland Attorney General Douglas F. Gansler
Massachusetts Attorney General Martha Coakley
Rhode Island Attorney General Peter Kilmartin
Vermont Attorney General William H. Sorrell

December 11, 2012

Lisa P. Jackson
Administrator
Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N. W.
Washington, DC 20460

RE: 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

Dear Administrator Jackson:

The States of New York, Connecticut, Delaware, Maryland, Rhode Island, and Vermont, and the Commonwealth of Massachusetts, respectfully request that the Environmental Protection Agency remedy its failure under the Clean Air Act to set performance standards for new sources and guidelines for existing sources that curb emissions of methane from the oil and gas sector. EPA has determined that emissions of this potent greenhouse gas endanger public health and welfare, and that processes and equipment in the oil and gas sector emit vast quantities of methane. Moreover, EPA has compelling data, including from 18 years of experience administering the Natural Gas Star Program, demonstrating that many measures to avoid (or reduce) methane emissions from new and existing oil and gas operations are available and cost-effective. Despite these findings, EPA has missed the applicable deadline for determining whether standards and guidelines limiting methane emissions from oil and gas operations under section 111 of the Clean Air Act are appropriate and for issuing such standards. EPA's ongoing failure to address the sector's methane emissions violates the Clean Air Act and harms the health and welfare of our residents.

I. Background

From severe droughts and heat waves to a string of devastating storms in the northeast over the last two years, it is becoming ever more apparent that increasing greenhouse gas pollution contributes to climate disruption in the U.S. and around the globe. Methane is a very potent greenhouse gas -- pound for pound, it warms the climate about 25 times more than carbon dioxide. EPA has found that the impacts of climate change caused by methane include "increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity and sea level rise." 77 Fed. Reg. 49,490, 49,535 (Aug. 23, 2011). Oil and gas systems are the largest source of methane emissions in the U.S. and the second largest industrial source of U.S. greenhouse gas emissions behind only electric power plants. For example, methane emissions from this sector make almost one-fifth of the contribution to climate change that carbon dioxide emissions from coal-fired power plants do. EPA must fully comply with its legal obligations under the Clean Air Act to regulate emissions that endanger public health and welfare by controlling this significant source of dangerous greenhouse gas pollution.

Section 111 of the Clean Air Act requires EPA to establish standards of performance governing the emission of air pollutants from new sources in the oil and gas sector and to review, and if appropriate, revise, those standards at least every 8 years. *See* 42 U.S.C. § 7411(b)(1)(B). As part of this 8-year review, EPA had a mandatory duty (1) to make a determination whether standards covering methane emissions are "appropriate," and, (2) if it is appropriate, to promulgate standards. The Act and EPA's regulations also require EPA to issue emission guidelines covering the release of methane from any existing oil and gas operations for which standards of performance have been issued. *See id.* § 7411(d); 40 C.F.R. § 60.22(a).

EPA originally promulgated standards of performance for the oil and gas sector in 1985. The 8-year deadline for reviewing these standards expired in 1993. EPA finally signed a rule to complete the mandated review for oil and gas operations on April 17, 2012. 77 Fed. Reg. 49,490 (Aug. 16, 2012). However, although the agency revised the standards for several pollutants, EPA did not make the required appropriateness determination regarding methane, nor did EPA establish performance standards or emission guidelines for methane emissions from this industrial sector.

Consequently, unless you promptly correct these failures, we intend to file suit in federal district court against you as EPA administrator and EPA for failures to timely:

(1) make the required determination whether standards of performance limiting methane emissions from oil and gas sources are appropriate and, if so, failing to timely issue revised performance standards limiting methane emissions from this source category; and

(2) issue emissions guidelines for the control of methane emissions from existing oil and gas sources.

Jurisdiction to adjudicate and enforce the Administrator's failure to carry out non-discretionary duties lies with the district court under section 304 of the Act. *See Environmental Defense Fund v. Thomas*, 870 F.2d 892, 897 (2d Cir. 1989); *Portland Cement Ass'n v. EPA*, 665 F.3d 177, 194 (D.C. Cir. 2011). This letter provides notice as required under section 304 of the Clean Air Act, 42 U.S.C. § 7604, and 40 C.F.R. part 54. Unless EPA takes the required actions by the end of the applicable notice period, we intend to bring a suit for EPA's failure to perform the non-discretionary duties outlined in 42 U.S.C. §§ 7411(b)(1)(B), 7411(d), and 40 C.F.R. § 60.22(a), and for the agency's unreasonable delay in the performance of these duties. The suit will seek injunctive and declaratory relief, the costs of litigation, and may seek other relief.

II. EPA Failed to Perform Its Non-Discretionary Duties to Determine Whether Standards of Performance for Methane Are Appropriate and, if so, to Establish Such Standards and Related Emissions Guidelines.

Section 111 of the Clean Air Act requires EPA to establish "standards of performance" for emissions of air pollutants from categories of new, modified, and existing sources. After EPA sets initial standards of performance for a listed category, section 111(b)(1)(B) imposes a timetable for EPA to review and revise those standards: "The Administrator shall, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by the subsection for promulgation of such standards." 42 U.S.C. § 7411(b)(1)(B). EPA failed timely to review the standards of performance that it initially established in 1985 for sources in the oil and gas sector, leading multiple groups to file suit in 2009 to compel such review. That case, *Wild Earth Guardians v. EPA*, No. 1:09-CV-00089 (D.D.C.), resulted in a consent decree setting forth a schedule for proposing any final revisions by November 30, 2011.

In August 2011, EPA proposed revisions to the oil and gas NSPS. 76 Fed. Reg. 52,738 (Aug. 23, 2011). EPA did not propose any standards for methane emissions, despite previously determining that methane and other greenhouse gases endanger public health and welfare. 74 Fed. Reg. 66,496 (Dec. 15, 2009). Numerous organizations submitted comments on the proposed rule stating that EPA was required, as part of its mandated 8-year statutory review, to determine whether it was "appropriate" to add standards of performance for additional, previously-unregulated pollutants, such as methane, and, if so, to revise them accordingly.

EPA signed a final rule revising some aspects of the oil and gas standards on April 17, 2012, which was published in the Federal Register on August 16, 2012. 77 Fed. Reg. 49,490. EPA failed to determine whether it is appropriate to establish methane standards. Instead, EPA stated that "[i]n this rule, we are not taking final action with respect to regulation of methane. Rather, we intend to continue to evaluate the appropriateness of regulating methane with an eye toward taking additional steps if appropriate." *Id.* at 49,513. The agency further stated that "over time," it would assess emissions data received pursuant to the recently implemented greenhouse gas emissions reporting program, but set forth no timetable for taking final action to address methane emissions. *Id.*

EPA's failure to decide one way or another within the 8-year statutory review deadline whether it is appropriate to revise the oil and gas NSPS to regulate methane emissions violates section 111(b)(1)(B) of the Clean Air Act. That section imposes a clear-cut nondiscretionary duty of timeliness that requires EPA to make a decision within the 8-year review period whether it is "appropriate" to revise the standards to regulate methane, regardless of whether the substance of that decision is discretionary. The Second Circuit Court of Appeals in *Thomas*, 870 F.2d at 900, held that substantially similar language contained in section 109(d) of the Clean Air Act -- which provides that, at five-year intervals, EPA "shall complete a thorough review" and "promulgate such new standards as may be appropriate"-- imposed a nondiscretionary duty to make a decision. In that case, like here, EPA had declined to make any formal decision to either revise or decline to revise the standards for a specific pollutant. EPA argued that its non-decision was unreviewable by the D.C. Circuit under section 307 because it involved no decision or other agency "action" and was also not subject to challenge in district courts under section 304 because it was discretionary." *Id.* at 896. The Court rejected EPA's argument, holding that EPA may not leave the matter "in a bureaucratic limbo subject neither to review in the District of Columbia Circuit nor to challenge in the district court. *Id.* at 900. While the Court agreed that the "as may be appropriate" language of section 109(d) provided EPA with discretion to determine whether revision was appropriate and what the substance of those revisions should be, the presence of the language "shall complete" and "required" in that section implied that the district court "has jurisdiction to compel the Administrator to make *some* formal decision whether or not to revise the [standards]." *Id.*

Here, section 111(b)(1)(B) contains the mandatory term "shall" -- which applies to both of the verbs "review" and "revise"-- and a clear-cut statutory deadline of "at least every 8 years." Because EPA cannot make any revisions without first completing its review, the language requires EPA to both complete the review and make the revisions within the 8-year review period. Therefore, a district court has jurisdiction to compel EPA to make a determination one way or another as to whether revision of the oil and gas NSPS is appropriate and to issue any revision it determines is appropriate.

In addition, EPA has a mandatory duty to include in its 8-year review new pollutants like methane that it has not previously regulated, but that it has since determined endanger public health and welfare. It would be wholly inconsistent with the mandatory nature of section 111 if EPA could refuse to address, as part of its 8-year review, air pollutants that are emitted by an already-listed source category and that EPA has already determined endanger public health and welfare. Rather, the structure of the Act demonstrates Congress' intent that EPA thoroughly review and revise NSPS for a source category at least every 8 years and not limit such review to making changes to existing standards, but instead require EPA to enact more stringent air pollution requirements as circumstances change, as new information becomes available regarding the adverse public health and welfare effects of air pollutants, and as new technologies become available to control emissions of such pollutants. Congress contemplated the 8-year review to encompass EPA's revision of the standards to address other air pollutants, particularly those emitted by a source category that, based on current information, are now determined to significantly contribute to that source's endangerment of public health and welfare and/or for which there is demonstrated control technology available. Further, EPA's past practice confirms that the agency must consider during its 8-year review all of the air pollutants emitted by the source category under review and set NSPS for any of those pollutants that cause or contribute significantly to that source's endangerment of public health and welfare and for which there is demonstrated control technology. *See* 41 Fed. Reg. 3826-27 (Jan. 26, 1976) (addition of standards for SO_2 and CO in NSPS for primary aluminum reduction plants); 42 Fed. Reg. 22506-07 (May 3, 1977) (addition of standards for NO_X, SO_2, and CO in NSPS for lime manufacturing plants); 49 Fed. Reg. 25,106-07 (June 19, 1984) (addition of standards for PM, CO, and hydrocarbon emissions in NSPS for fossil fuel-fired industrial steam generating units).

EPA failed to act on regulation of methane under section 111 despite possessing extensive information that adding methane standards for oil and gas operations is "appropriate." In prior 8-year reviews of standards of performance under section 111, EPA has consistently applied two criteria in determining whether it is appropriate to include a standard for a health- and welfare-endangering air pollutant: (i) the extent of the source category's contribution to the emissions of the pollutant, and (ii) the availability of methods to reduce those emissions. *See, e.g.*, 75 Fed. Reg. 54,970 (Sept. 9, 2010) (finalizing new NO_x standard for cement plants). Applying these criteria to the oil and gas sector demonstrates that methane standards are appropriate at this time.

First, EPA has recognized that "processes in the Oil and Natural Gas source category emit significant amounts of methane." 76 Fed. Reg. at 52,756/1. Indeed, the proposal stated that the sector's methane emissions are equivalent to more than 328 million metric tons of carbon dioxide per year. *Id.* at 52,756/2. As a result, oil and gas operations are the second largest industrial source of U.S. greenhouse gas emissions, behind only electric power plants. *Cf.* 74 Fed. Reg. 16,448, 16,597 Table VIII-1 (April 10, 2009) (showing 2009 estimates of greenhouse gas emissions from other industrial source categories). As EPA explained in the 2012 final rule, "methane emissions from the oil and gas industry represent about 40 percent of the total methane emissions from all sources and account for about 5 percent of all CO_2e [carbon dioxide equivalent] emissions in the United States, with natural gas systems being the single largest contributor to United States anthropogenic methane emissions." 77 Fed. Reg. at 49,535/2. Although EPA projects that the standards adopted in the 2012 final rule for emissions of volatile organic compounds (VOCs) and hazardous air pollutants will have the incidental benefit of also reducing annual methane emissions by about 19 million metric tons CO_2e, *id.* at 49,535/3, the vast majority of methane emissions from this sector will remain uncontrolled.

EPA's failure even to consider directly controlling methane emissions through standards and guidelines resulted in the omission of controls for certain operations that emit large amounts of methane.

For example, EPA declined to establish standards for compressors and pneumatic controllers in the natural gas transmission and distribution segment asserting that, although this equipment emits large quantities of methane, much of the VOCs already have been removed by the time the natural gas stream reaches these sources. *See* 77 Fed. Reg. at 49,522-23 (declining to regulate transmission and distribution compressors because of "the relatively low level of VOC emitted from these sources").

Second, there are readily available methods to reduce methane emissions. In fact, the high methane content of these currently uncontrolled emissions means that adopting standards and guidelines that require methane emissions controls would be cost-effective (or even profitable) at many of these additional emission points. In the final rule, EPA recognized the economic value of emissions control measures for oil and gas equipment that lead to the recovery of hydrocarbon products, including methane, "that can be used on-site as fuel or reprocessed within the production process for sale." 77 Fed. Reg. at 49,534/1. Indeed, EPA found that the rule "will result in net annual costs savings of about $11 million (in 2008 dollars)." *Id.* By ending the waste of methane at sources of emissions not covered by the standards for VOCs, standards of performance that address methane emissions directly likely would add to the economic benefits of the rule. For instance, although compressors located at a wellhead or in the transmission, storage, and distribution segment are not covered under the rule, 77 Fed. Reg. at 49,492/2, EPA has determined that the payback period for compressor maintenance activities that reduce methane emissions is a mere 1 to 3 months. *See* EPA, "Reducing Methane Emissions from Compressor Rod Packing Systems" (Oct. 2006) at 1 (indicating payback periods from 1 to 3 months for compressor maintenance activities that reduce methane emissions). In addition, through EPA's voluntary Natural Gas Star Program, EPA has worked with oil and gas companies to identify more than 100 cost-effective technologies and practices to reduce methane emissions from sources of emissions not covered by the rule. *See* http://www.epa.gov/gasstar/tools/recommended.html.

Section 111(d) of the Clean Air Act also requires EPA to address methane emissions from existing sources, as well as from new and modified facilities. 42 U.S.C. § 7411(d)(1)(A). The Act requires EPA to establish procedures under which each state submits to the agency a plan to adopt, implement, and enforce standards of performance for existing sources for certain pollutants, and to promulgate standards of performance under such plans. *Id.* § 7411(d). The existing source requirements apply to those pollutants, such as methane, that have not been identified as criteria pollutants or hazardous air pollutants, but that are regulated under the new source performance standards for a category of sources. *Id.* § 7411(d)(1). Thus, the Act creates a direct connection between the new source standards and those to be developed for existing sources.

EPA's regulations require the agency to publish "emissions guidelines" "which reflect[] the degree of emission reduction achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated for designated facilities." 40 C.F.R. §§ 60.21(e), 60.22(a, b). These guidelines are implemented by state agencies who develop and submit to EPA plans to curb emissions of designated pollutants from existing sources. *Id.* § 60.23(a); 42 U.S.C. § 7411(d)(1). EPA has issued emission guidelines at the same time as new source standards for a listed category. *See* 62 Fed. Reg. 48,348 (Sept. 15, 1997) (standards of performance and emissions guidelines for hospital/medical/infectious waste incinerators); 61 Fed. Reg. 9905 (Mar. 12, 1996) (same for municipal solid waste landfills); 60 Fed. Reg. 65,387 (Dec. 19, 1995) (same for municipal waste combustors).

In sum, EPA has failed to review and update as necessary the existing oil and gas standards. EPA's continuing failure to make a final appropriateness determination during its 8-year review and to make the necessary revisions is contrary to section 111(b)(1)(B) of the Clean Air Act. *See* 42 U.S.C. § 7411(b)(1)(B). EPA's failure to make an appropriateness determination also has prevented EPA from fulfilling its duty to publish emissions guidelines covering methane emissions from existing facilities in the oil and gas sector. EPA's continuing failure to publish these guidelines is contrary to section 111(d) of the Clean Air Act and the regulations implementing that section. *See* 42 U.S.C. § 7411(d); 40 C.F.R. § 60.22(a). We are therefore providing notice that, as of 60 days from the date of this letter, we intend to sue you as EPA administrator and EPA for EPA's failure to take these non-discretionary actions.

III. EPA Has Unreasonably Delayed Determining Whether Standards of Performance for Oil and Gas Operations Are Appropriate and, if so, Establishing Such Standards and Related Emissions Guidelines.

As set forth above, section 111(b)(1)(B) imposes a non-discretionary duty on EPA to review and, if appropriate, revise the NSPS for each category of sources, and section 111(d) and 40 C.F.R. § 60.22(a) impose a non-discretionary duty to establish emissions guidelines covering existing sources. Even if those provisions can be read to contain any ambiguity as to the deadline for these mandatory duties, EPA has unreasonably delayed taking action on methane emissions from the oil and gas sector.

EPA has long known the significance of the oil and gas sector's contribution to methane emissions and the availability and cost-effectiveness of measures for reducing those emissions. EPA's knowledge that oil and gas operations are one of the nation's largest methane sources dates to at least 1997, as the agency has published annual sector-by-sector inventories of U.S. greenhouse gas emissions since 1997, covering emissions since 1990.[1] Similarly, EPA has long had ample data on measures for controlling methane emissions. For example, in 2008, EPA explained that because of its experience implementing the agency's Natural Gas STAR Program, a voluntary public-private partnership with the oil and gas industry initiated in 1993, "many of [the] technologies and management practices" available to control methane emissions from the sector "have been well documented (including information on cost, benefits and reduction potential) and implemented in oil and gas systems throughout the U.S." EPA, Office of Air and Radiation, Technical Support Document for the Advanced Notice of Proposed Rulemaking for Greenhouse Gases; Stationary Sources, Section VII at 30 (June 2008).

EPA has been actively engaged in rulemaking to revise the oil and gas sector standards of performance at least since April 2010, when the agency began sending requests to visit regulated facilities to gather information. *See, e.g.*, Letter from K.C. Hustvedt, EPA, to Tom Monahan, ExxonMobil Production Co. (Apr. 30, 2010) Docket No. EPA–HQ–OAR–2010–0505-0053. In response to the 2009 litigation discussed above, EPA proposed revisions to the standards of performance for oil and gas operations in August 2011. 76 Fed. Reg. at 52,738. However, instead of drawing on the successes of the Natural Gas Star Program to propose a course of action, or even soliciting comment on the issue, the agency chose to ignore the problem. The proposal stated only that "[a]lthough this proposed rule does not include standards for regulating [methane emissions], we continue to assess these significant emissions and evaluate appropriate actions for addressing these concerns." *Id.* at 52,756/2. Multiple parties filed comments in November 2011 objecting to the failure to propose methane standards for this source category. Commenters argued that EPA had abundant evidence that uncontrolled methane emissions from oil and gas operations significantly contribute to atmospheric greenhouse gas pollution, that control measures are available and cost-effective, and that methane standards therefore are appropriate and legally required. *See, e.g.*, Comments of Sierra Club et al. at 74-80 (Nov. 30, 2011) Docket No. EPA–HQ–OAR–2010–0505-4240.

Notwithstanding these comments and the detailed information EPA already had in its possession, the agency has failed to make any appropriateness determination regarding the oil and gas sector's

[1] Links to each annual GHG emissions inventory are at http://www.epa.gov/climatechange/emissions/usgginv_archive.html.

methane emissions, or to propose or promulgate performance standards to meet its obligations under section 111(b)(1)(B) of the Act with regard to the oil and gas sector's methane emissions. EPA's failure to complete the rulemaking required under section 111(b)(1)(B) to address methane emissions from new and modified oil and gas operations has also resulted in an unreasonable delay in establishing emissions guidelines for the controlling methane emissions from existing oil and gas sector sources. EPA's unreasonable delay in issuing these guidelines in turn delays both the date by which states must submit plans for the control of methane from existing oil and gas operations, 40 C.F.R. § 60.23(a), and the date by which existing sources must comply with approved pollution control standards, *see id.* § 60.24(c). Therefore, we are also providing 180-day notice that we intend to sue you as EPA administrator and EPA for EPA's unreasonably delaying final agency action to determine whether standards for methane emissions from oil and gas operations are appropriate, to make the necessary revisions to 40 C.F.R. Part 60, and to issue emissions guidelines for methane emissions from existing oil and gas operations.

IV. Conclusion

EPA's acknowledgement that oil and gas operations account for a large share of methane emissions points to the urgent need to reduce these emissions. The agency's long experience with control strategies that recover methane emissions from oil and gas operations for productive uses confirms that there are cost-effective measures for this source category that would provide an appropriate basis for establishing a standard of performance for methane emissions. But EPA's failure to make progress in deciding whether standards are appropriate demonstrates that litigation may be needed to prompt the required agency action. Accordingly, the States of New York, Connecticut, Delaware, Maryland, Rhode Island, and Vermont, and the Commonwealth of Massachusetts, submit this notice of intent to sue for EPA's failure to complete the review of the standards of performance for oil and gas operations as mandated by section 111(b)(1)(B) of the Clean Air Act and for the agency's unreasonable delay in the completion of that action. The States of New York, Connecticut, Delaware, Maryland, Rhode Island, and Vermont, and the Commonwealth of Massachusetts, also give notice of their intent to sue for EPA's failure to complete the emissions guidelines for existing sources required by section 111(d) of the Clean Air Act and EPA's regulations at 40 C.F.R. § 60.22(a) and for the agency's unreasonable delay in the completion of that action.

We are willing to explore any effective means of resolving this matter without the need for litigation. However, if we do not hear from you within the applicable time periods provided in section 304 of the Act, we intend to file suit in United States District Court.

Very truly yours,

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Appendix G

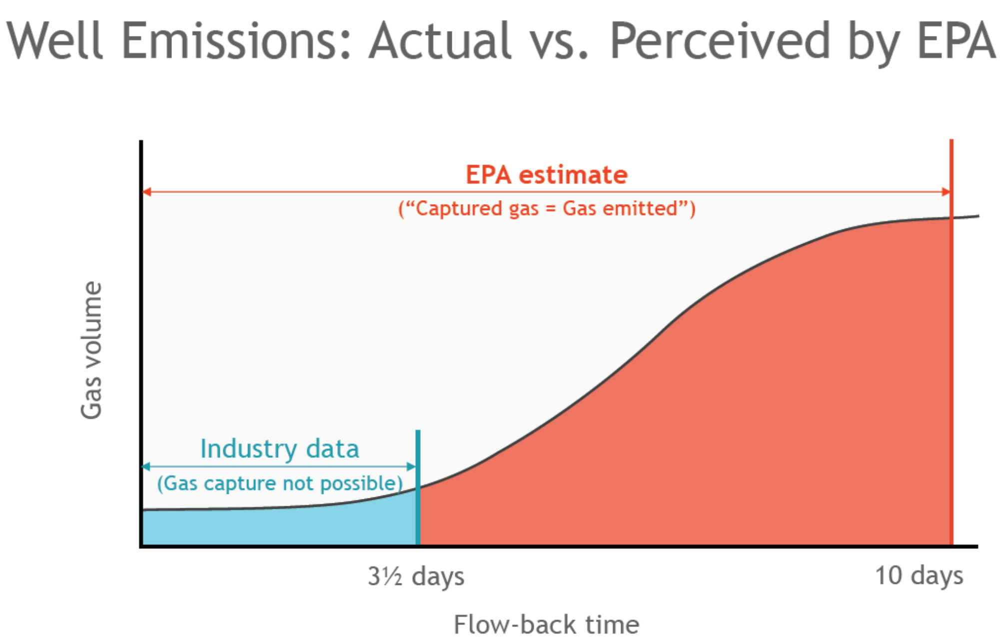
Testimony for *America's Energy Future, Part I: A Review of Unnecessary and Burdensome Regulations* presented by Joe Leonard, Devon Energy Corporation

Before The Committee on Oversight and Government Reform on July 13, 2012, Edmond, OK

Good morning and thank you for providing the opportunity to testify on such an important issue. My name is Joe Leonard, and I am the Environmental, Health and Safety Engineer for Devon Energy with a particular technical expertise in air quality.

EPA's unreasonable and inappropriate misuse of industry data and bad science leads to unnecessary and burdensome air quality regulations on the oil and gas industry. I would like to focus on two examples of this today.

First, I would like to address EPA's development of an emission factor for well completions by improperly using Natural Gas STAR data. In short, the EPA assumes that gas recovered would have otherwise been flared or vented. However, industry data shows that reduced emission completions account for significantly more gas produced and sold than would be flared or vented during older and less common completion processes. The below figure depicts the comparison between what EPA perceives and what industry data actually shows.



EPA's fundamental misperception of initial gas production from natural gas wells leads to dramatic overestimates of methane emissions.

Second, EPA Region 6 recently designated Wise County in the State of Texas, a significant gas production and transmission area, to be in "nonattainment" for ozone. Region 6's argument can best be described as arbitrary and capricious. Their stance rests on only two data points and their attempt to link Barnett Shale gas production development. The science behind the designation is lackluster, and relies on methods rejected by other EPA regions.

<u>EPA's flawed methane emission estimates continue to mischaracterize natural gas</u>

In regards to flawed completion emissions, EPA continues to state that reduced emission completion estimates are reasonable estimates for gas that would have otherwise been flared or vented – despite a wealth of data showing that those estimates are dramatically overstated. This overstatement is consistent with the latest industry study from API/ANGA of more than 90,000 wells that demonstrated estimates were at least 100% too high across upstream processes. This work follows similar industry work that shows even greater errors.

This is outrageous because EPA, using incorrect assumptions, applying inappropriate data, and then analyzing it improperly, has not only changed its emission estimates for completion operations on a forward-looking basis, <u>but revised all oil and gas completion estimates back to 1990 – a period before the combined use of horizontal drilling and hydraulic facturing</u>. Since revising its estimates, EPA submitted those estimates as part of the US input to the UN Intergovernmental Panel on Climate Change, giving it a worldwide audience.

The effect of the revision has allowed for the mischaracterization of natural gas. Non-governmental organizations and university studies have claimed that (on a life-cycle basis) gas-fired electricity generation is no cleaner than coal-fired, and that natural gas-powered vehicles are no cleaner than those running on gasoline. The ripple effects like these will continue until EPA acknowledges and corrects this inaccurate data. Severe damage has been inflicted on the many benefits of using natural gas as a clean fuel that will last for years to come. EPA must exercise more scrutiny in their methods for calculating such factors if the oil and gas industry is to be represented fairly. This issue proves that casual efforts on the part of the EPA can have such a strong and negative impact to our industry.

<u>Wise County, TX nonattainment ruling is based on analysis rejected by other regions</u>

As I mentioned earlier, EPA has recently designated Wise County, TX, as an ozone non-attainment area contributor. An area is considered "nonattainment" when it exceeds a national air standard, in this case ozone. The area must then take steps to come to "attain" the standard, or come into "attainment".

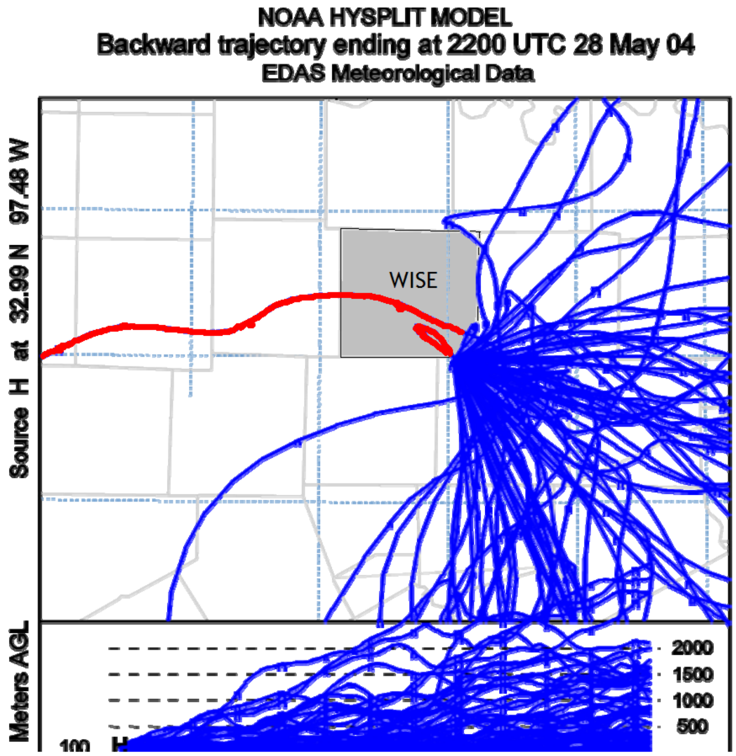
That action, in Region 6, was initiated under a since-resigned regional administrator who once likened enforcement action approaches to the oil and gas industry to what might be described as examples-by-crucifixion. There are several other concerns when analyzing their justification for nonattainment.

Concern 1: The model used by Region 6 is inadequate for modeling ozone formation and transport. Other regions specifically refused to use this method because of its unreliability.

Concern 2: The model only traced two events over four years passing through Wise County, one of which originated in the notoriously nonattainment Tarrant County, which is coincidently the same county of the only monitor that EPA provided results for. Data shows that winds blow from Wise County into Tarrant County less than three percent of the time. Other EPA regions denied nonattainment considerations based solely on wind occurrences of less than 20% of the time.

Concern 3: We do not know the results from other monitors downstream of the prevailing wind from Wise County. If the EPA Region 6 wanted to justify Wise County as a contributor of ozone, why did they not provide results from more representative monitors? As the Texas Commission of Environmental Quality described, the presented data seems to be "cherry-picked".

The below figure contained in this handout shows a composite of all modeling results done by EPA Region 6, with the two Wise County events highlighted in red.



If Wise County is in fact nonattainment, then Devon will diligently comply with the regulations, but we do not believe the EPA's argument, or the data supporting their decision.

In conclusion, it is difficult to adequately capture all of the unnecessary and burdensome air regulations imposed on our industry. I hope that the examples of completion emission estimates and Wise County Nonattainment provide at least some insight into this issue.

This concludes my testimony. Thank you.

Joe Leonard – Devon Energy Corporation – 405.552.4740 or joe.leonard@dvn.com

Bio for Joe Leonard:

Joe Leonard is the Environmental, Health, and Safety Engineer for Devon Energy Corporation, and has been with the company in that position since January of 2010. As an EHS Engineer for the company, Joe is responsible for supporting all areas regarding air quality calculations as well as state and federal regulation interpretation. He also acts as a technical air quality expert in both Devon Energy and among several trade organizations.

He received his Bachelor of Science degree in Chemical Engineering at Oklahoma State University, and has a brief work background in oil and gas processing and transmission.

Committee on Oversight and Government Reform
Witness Disclosure Requirement – "Truth in Testimony"
Required by House Rule XI, Clause 2(g)(5)

Name: Joe Leonard

1. Please list any federal grants or contracts (including subgrants or subcontracts) you have received since October 1, 2009. Include the source and amount of each grant or contract.

None

2. Please list any entity you are testifying on behalf of and briefly describe your relationship with these entities.

Devon Energy Corporation - I am an employee

3. Please list any federal grants or contracts (including subgrants or subcontracts) received since October 1, 2009, by the entity(ies) you listed above. Include the source and amount of each grant or contract.

None

I certify that the above information is true and correct.
Signature:

Date: 7/11/12

Appendix H

A Brief Review of Statistical Methods and Procedures Contained in EPA Document "Evaluation of the Emission Factor for Hydraulically Fractured Gas Well Completions and Recompletions"

Executive Summary

- The EPA report uses summary data collected through programs designed for other purposes to investigate the possibility of shifting emission factors
- The result of this approach is a data set that is ill-defined, highly aggregated, and limited in usable observations
- The starting point of analysis is a simple ordinary least squares regression, resulting in an estimated average emission factor of 8900 Mcf with a standard error of 4168.5
- The smallest level of statistical significance at which the null hypothesis that the true emission factor is zero (as opposed to the estimated 8900) can be rejected is 0.122
- The lack of statistical significance is underscored by the inclusion of zero in the confidence interval constructed as
    - $8900 \pm 3.182 * 4168.5 \qquad -4366.13, 22166.1)$
- In order to achieve a statistically meaningful result, the researcher must justify a smaller value of the distributional parameter (3.182) and/or estimated standard error (4168.5)
- The first is accomplished with the assumption that the emissions variance is known, which changes the distributional assumptions of the interval estimate such that 3.182 (from the t-distribution) is replaced by 1.96 (from the normal distribution. This single assumption alone makes a previously insignificant result significant
- The second is accomplished by imposing a very tight prior belief on the variance of the mean emissions (based on GasStar summary data), which reduces estimated standard error from 4168.5 (OLS) to 1416.3 (Bayesian)
- The combined effect of the assumption of a known variance and imposition of a tight prior belief result in a final interval estimate of (6123, 11676)

- The crux of the concern lies in identifying the more appropriate interval estimate – the original and not statistically significant (-4366.13, 22166.1) or the alternative (6123, 11676)
- Based on the evidence provided in the technical document, we are uncomfortable with the assumption of a known variance. Not only is it unsubstantiated in the report, but it is unnecessary. Derivation of Bayesian interval estimates can proceed without this assumption
- We are similarly uncomfortable with the choice of such a tight prior belief of the mean variance. Given the small number of data points in the original analysis (4), using such a tight prior exerts considerable influence over the posterior distribution. Allowing the prior to dominate the information contained in the data is a practice Bayesian statisticians generally try to avoid[1]

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[1] EPA's primary objection will more than likely be that the prior is based on data.

Discussion

The comments contained in this review of "Evaluation of the Emission Factor for Hydraulically Fractured Gas Well Completions and Recompletions" reflect the initial thoughts and concerns of Jacob Dearmon, Ph. D, associate professor of economics, and Russell Evans, Ph. D, executive director of the Steven C. Agee Economic Research and Policy Institute, in the Meinders School of Business at Oklahoma City University. All comments expressed herein should be viewed as preliminary, with the authors reserving the right to expand, edit, or abridge their thoughts as time and access to data inform their positions.

The basic premise of the EPA document is that data on gas emissions from well completions and recompletions submitted voluntarily and through programs not designed explicitly to update estimated emission factors can be used to accomplish just that – updating EPA emission factors. The analysis centers on the aggregate level data associated with four data sets. Neither well level observations nor a full description of the underlying data sets are made available. Instead, inferences are limited to the information contained in the mean emissions per completion reported from these four sources. The table below summarizes the relevant information and is a re-creation of table 1-8 on page 1-16 of the report.

Data Source	Whole Gas, Average Emissions per Completion (Mcf)	Modified, Average Methane Emissions per Completion (Mcf)[2]	Rounded, Average Methane Emissions per Completion (Mcf)
Weatherford	667	555	600
Industry Data Set #1	5,820	4,844	5,000
Devon	11,900	9,905	10,000
William	24,449	20,351	20,000

Rounded values of whole gas emissions are used on page 1-3 of the report to estimate emissions per completion of 9,175 Mcf while rounded values of methane emissions per completion[3] are used to estimate average methane emissions per completion of 8,900 Mcf (page 1-16 of EPA report). The EPA analysis begins with what is essentially an ordinary least squares (OLS) regression of methane emissions on a constant and vector of unit scalars, the results of which are

[2] Modified emissions are calculated using a methane content value of 0.8324
[3] There is a mistake on the top of page 1-3. Summation operators are missing from the formula being used to calculate the average gas emissions.

reported below. The variable of interest in this case is the intercept of the regression equation which gives the average emissions across the four data points.

Model 2: OLS, using observations 1-4
Dependent variable: Emissions

	Coefficient	*Std. Error*	*t-ratio*	*p-value*
Const	**8900**	**4168.53**	2.1350	0.12243

Mean dependent var	8900.000	S.D. dependent var	**8337.066**
Sum squared resid	2.09e+08	S.E. of regression	8337.066
R-squared	0.000000	Adjusted R-squared	0.000000
Log-likelihood	-41.21426	Akaike criterion	84.42851
Schwarz criterion	83.81481	Hannan-Quinn	83.08178

The values in bold format are those reported in table 1-9 of the report, with the variance of the coefficient given by the square of the standard deviation, or 8337.066^2 or 69,506,666.7 (6.95+07 in table 1-9).

The regression tests the hypothesis that the true coefficient value is statistically different from zero. That is, the model asks whether or not there is sufficient information contained in the data points to reject the hypothesis that the true average methane emissions per completion – estimated to be 8,900 Mcf – is zero against the alternative hypothesis that average emissions is not zero. The null hypothesis, that the true value of average emissions per completion is zero, cannot be rejected at the 1%, 5%, or 10% significance levels.

The lack of statistical information contained in the data points is underscored by the fact that the corresponding interval estimate for the average methane emissions coefficient contains the value of zero. The 95% confidence interval is given by:

$$t\ (3,0.025) = 3.182$$

Variable	Coefficient	95% confidence interval
const	8900.00	(-4366.13, 22166.1)

This confidence interval differs from the confidence interval reported on page 1-17 of the EPA document. It appears that the authors of the EPA document have either incorrectly constructed or reported the 95% confidence interval. Regardless, note that both intervals contain the value of zero, suggesting insufficient evidence to conclude that the true value of average methane emissions per completion is statistically different from zero.

At this point in the analysis, the authors of the EPA report have two options. The first, and most prudent option in our opinion, is to conclude the analysis with the determination that a robust dataset of well-specific observations would be required to investigate further the possibility of shifting emissions factors due to alternative drilling techniques and exploration in non-traditional geologic formations. The second option, and that chosen by the authors of the EPA report, is to pursue a Bayesian approach in order to narrow the interval estimate of average methane emissions per completion. [4]

The Bayesian approach combines the data (the likelihood function) with the prior beliefs of the researcher (prior density) to arrive at a distribution that is proportional to the posterior density.

$$p(\theta|y) \propto p(y|\theta) * p(\theta)$$

where $p(y|\theta)$ is the likelihood function and $p(\theta)$ is the prior density and θ is the parameter to be estimated (which is μ in the EPA report). Thus, the posterior density represents a combination of data and prior beliefs. Depending on how the model is set-up and defined, there is a wide range of possible outcomes for the posterior density. On one extreme, a vague and uninformative prior combined with a likelihood function using a substantial amount of data results in a very data-driven posterior. On the other extreme, a very tight or restrictive prior combined with a data-poor likelihood function produces a prior-driven posterior, which would reflect the researcher's prior beliefs rather than the data. It is our opinion that the posterior distribution calculated in the EPA's report is driven by the prior rather than the data.

[4] The fundamental difference between the authors of the EPA report and the authors of this comment is in regards to the width of the interval estimate. The authors of the EPA report believe that the interval is narrow based on very tight prior beliefs and the assumption of a known variance. The authors of the comment believe that the true interval estimate should be wider based on uninformative prior beliefs, data and an unknown variance.

In Figure 1, both the prior and OLS distribution for mean methane emissions are displayed. Both distributions are centered about the mean of 8,900. The spread of possible outcomes for the two distributions are very different, however. The OLS data-driven results have a very wide spread about the mean with a significant portion of that distribution's support falling on the negative part of the real line. In contrast, the prior has a very tight fit with most of its support restricted to a small range about the mean. Given that we have such a tight prior and such a limited amount of data (just 4 observations), we would expect that the prior rather than the data would be the defining influence on the posterior.

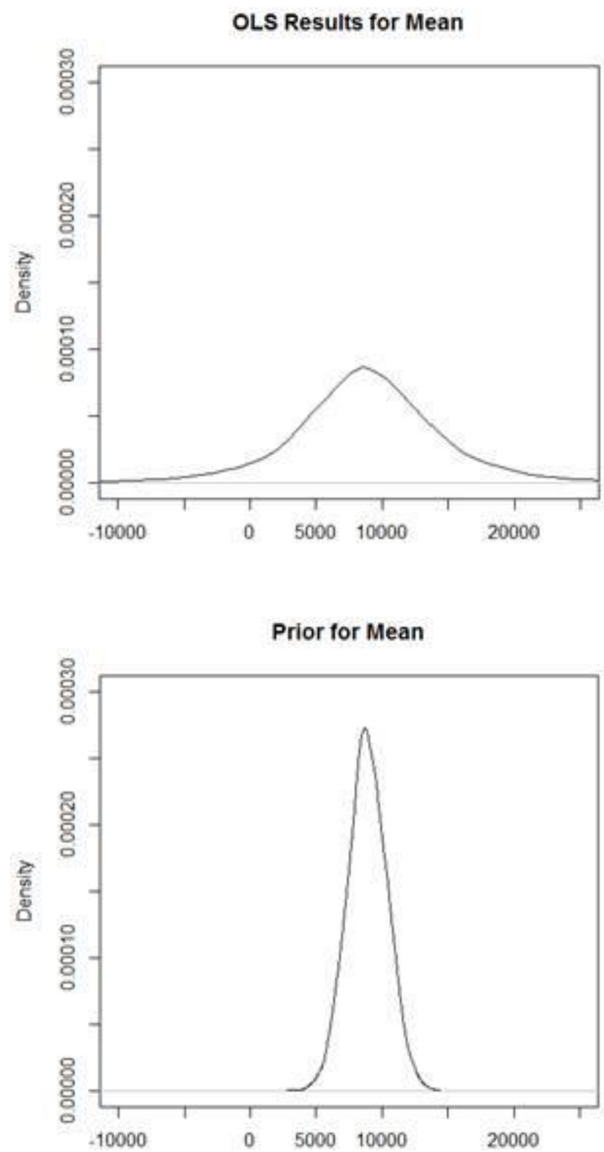


Figure 1. Distribution of Mean Methane Gas per Completion (Mcf)

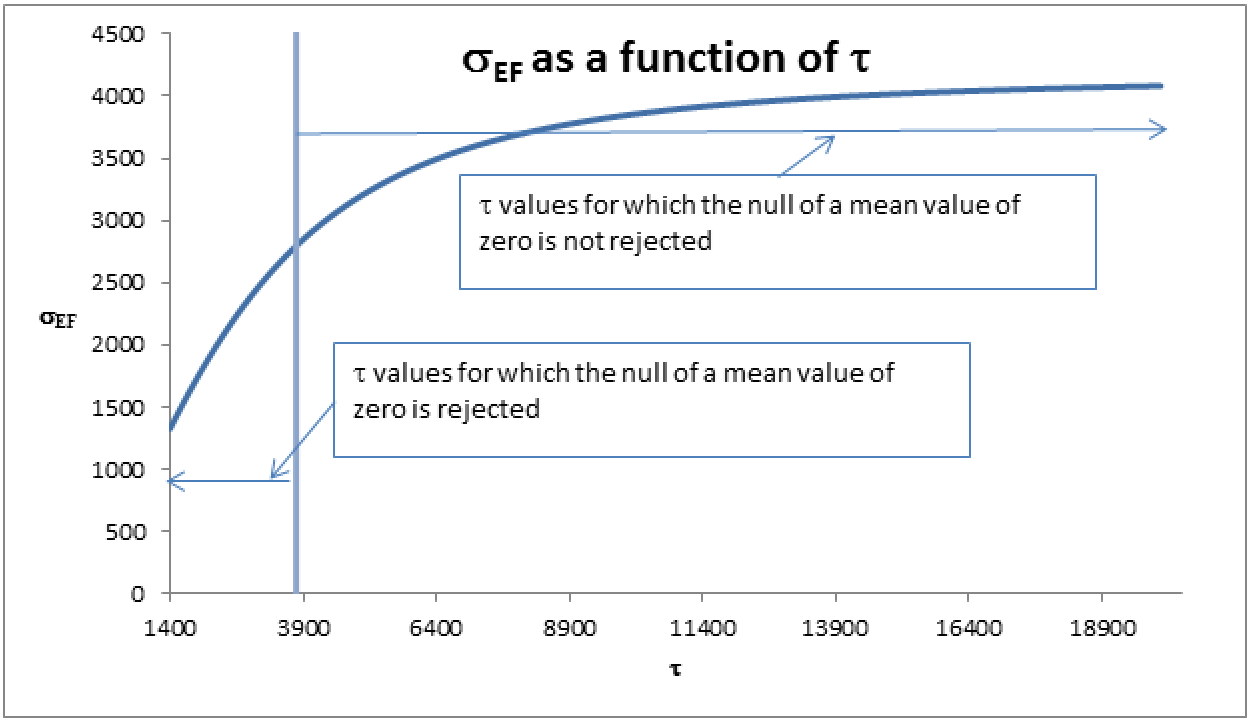
Just how sensitive is the interval to the choice of prior in this case? The following formula is found on p. 1-16 of the EPA's document

$$\sigma_{EF}^2 \quad \frac{1}{\frac{1}{\tau^2}+\frac{4}{\sigma^2}}$$

where σ^2 is $6.95 * 10^7$ and τ^2 is the variance associated with the prior for the mean. Lower values for τ imply a tighter prior and reduce σ_{EF} leading to a more narrow interval and tighter distribution (such as the prior in Figure 1). Higher values for τ imply a more uninformative prior that increases σ_{EF}, widens the interval estimate, and produces a broader distribution.

To model this trade-off between τ and σ_{EF} more explicitly, we conduct a sensitivity analysis. Holding σ constant, we can calculate how σ_{EF} varies as τ changes. When $\tau \quad 1506$, σ_{EF} is equal to the EPA's posterior estimate of 1416.35.[5] When τ is increased to $75{,}000$, σ_{EF} (= 4,162.1) becomes nearly equal to the OLS estimate of $4{,}168.5$. In Figure 2 below, τ is varied from the EPA's proposed value of 1,506 to 20,000. As τ increases, the prior becomes less informative and σ_{EF} increases which serves to widen the associated interval. At $\tau \quad 20{,}000$, the prior is relatively uninformative and more weight is placed on the data such that σ_{EF} (=4081) is much closer to the original OLS estimate. The green line indicates the minimum τ value at which the null hypothesis zero mean emissions cannot be rejected at the 5% level if a t distribution is assumed. Given that the EPA's choice of τ drops the standard deviation of the posterior estimate 66% from the OLS estimate, we can conclude that the prior in this model seems to be exerting a considerable amount of influence over the posterior; a practice that Bayesian statisticians or econometricians usually try to avoid.

[5] Please note that the EPA's first usage of σ_{EF} (1416.3) on page 1-18 differs slightly from their second usage of that variable (which is 1416.5)).



In addition to the choice of a very tight prior, there is also another questionable modeling choice. In particular, the authors of the EPA document assume that the variance is known. From p. 1-16, "*The four observations of the emission factors data are assumed to be normally distributed with a mean of μ and a known variance of* σ^2*, set equal to the sample variance.*" If there is a reason, statistical or otherwise, to believe that the variance is known and is in fact equal to the sample variance, it is not presented in the text. The implication of the assumption of known variance is to allow the distributional parameter used in the construction of the confidence intervals to shrink from the 3.182 associated with the t-distribution to the 1.96 associated with the normal distribution (see formula on page 1-18 of the report). This single, unsupported assumption alone would shift the lower bound of the confidence interval from -4366.13 to 729.74. Again, to underscore the importance of this assumption, note that where the variance is assumed to be unknown, the hypothesis that the true value of methane emissions per completion is zero could not be rejected at the 10% level of significance. If one adopts the assumption of known variance – without any other changes in the analysis – the hypothesis of zero emissions can be rejected at 5% significance level! Like magic, a statistically insignificant result is made significant with a single assumption!

Further, the assumption of a known variance for the mean seems to be very strong, especially in light of the substantial differences in these amounts across datasets. Therefore, the modeling approach employed should account for the fact that both the mean and the variance are unknown. Fortunately, estimating such a model within a Bayesian context is relatively straightforward. This model would be better able to account for this high degree of uncertainty and would serve to increase the interval. A commonly used Bayesian technique for linear regression where both the mean and the variance are unknown has a normal gamma for its posterior distribution. In this case, after having integrated out the variance, the marginal posterior density for the mean is distributed as a t rather than as a normal.

The issue of an unknown variance and tight prior are not unrelated. The degrees of freedom associated with this marginal posterior density depend on both the sample size and the weight applied to the prior. A prior that is too tight or restrictive will increase the degrees of freedom leading to a distribution that more closely approximates the normal distribution shrinking the intervals, ceteris paribus. Consequently, a tight prior with limited amount of data could still affect a model where the variance is unknown.

Conclusion

The reviewed report uses traditional techniques on a very small data set of gas emissions to derive an interval estimate of mean emissions per completion. The interval estimate is quite wide and includes zero, suggesting an inability to reject a null hypothesis that the true emissions value is zero. The report then moves to an alternative interval estimate based on simple Bayesian techniques. We identify several significant statistical objections to the manner in which the Bayesian methodology is employed in this report. First, a tight prior belief of the variance of the mean methane emission is imposed on very small data set, effectively imposing the researcher’s beliefs on the outcome. This practice is generally discouraged by Bayesian statisticians who prefer data driven posterior density functions when constructing credible confidence intervals. Second, assuming a known variance where no such assumption is warranted further narrows the resultant interval estimate. Ultimately, we find no reason to accept the narrow interval estimate as more credible than the original, given its construction is heavily dependent on the prior beliefs and assumptions of the researchers.