Shale Gas Production: Potential versus Actual GHG Emissions

Francis O'Sullivan and Sergey Paltsev

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Shale Gas Production: Potential versus Actual GHG Emissions

Francis O'Sullivan*† and Sergey Paltsev*‡

Abstract

Estimates of greenhouse gas (GHG) emissions from shale gas production and use are controversial. Here we assess the level of GHG emissions from shale gas well hydraulic fracturing operations in the United States during 2010. Data from each of the approximately 4,000 horizontal shale gas wells brought online that year is used to show that about 900 Gg CH4 of potential fugitive emissions were generated by these operations, or 228 Mg CH4 per well—a figure inappropriately used in analyses of the GHG impact of shale gas. In fact, along with simply venting gas produced during the completion of shale gas wells, two additional techniques are widely used to handle these potential emissions, gas flaring, and reduced emissions "green" completions. The use of flaring and reduced emission completions reduce the levels of actual fugitive emissions from shale well completion operations to about 216 GgCH4, or 50 Mg CH4 per well, a release substantially lower than several widely quoted estimates. Although fugitive emissions from the overall natural gas sector are a proper concern, it is incorrect to suggest that shale gas-related hydraulic fracturing has substantially altered the overall GHG intensity of natural gas production.

Contents

1. INTRODUCTION

Over the past decade, economically recoverable shale gas has transformed the U.S. natural gas industry, with some analysts characterizing it as a "revolution" (Deutch, 2011; Jacoby *et al.*, 2012). With shale driven growth, the U.S. has become the world's largest gas producer (IEA, 2011). The low gas prices that have accompanied this production boom have led to a renewed growth in gas demand by industrial users, a recovery viewed as extremely unlikely just a decade ago. The rise of shale gas has not been without controversy, however, with important concerns raised regarding water pollution (Osborn *et al.*, 2011), greenhouse gas (GHG) emissions, particularly those related to hydraulic fracturing (Howarth *et al.*, 2011a; Howarth *et al.*, 2011b; Howarth *et al.*, 2012), and uncertainty in estimates of the resource scale (Jacoby *et al.*, 2012; Urbina, 2011; MIT, 2011; Lee *et al.*, 2010). In this analysis we focus on the issue of fugitive GHG emissions associated with shale gas fracturing and provide estimates of potential and actual emissions.

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2. HYDRAULIC FRACTURING AND GHG EMISSIONS

The economic production of shale gas is only possible through the use of hydraulic fracturing to increase production rates from the extremely low-permeability shale formations. The hydraulic fracturing process has two main stages: injection and flowback. During injection, a slurry made up of a carrier fluid, typically water, and a proppant agent, typically sand, is forced into the well at pressures significant enough to induce fractures in the reservoir rock. These propped fractures allow gas in the formation to flow from the well at economically acceptable rates. After the injection phase is completed, flowback takes place. Here some of the initially injected fluid returns to the surface over the course of a week or more. During flowback, the well also begins to produce gas. It is the amount of this gas, and how it is handled, that has been central to the debate about the GHG intensity of shale development. In 2011, the EPA revised upwards its GHG inventories for the natural gas system (EPA, 2011), and some have attributed this increase to the expanded production of shale gas and the associated increase in hydraulic fracturing. It has been argued that large amounts of gas are directly vented to the atmosphere during flowback, and that this means shale gas has a significantly higher GHG intensity than conventional gas production (Howarth *et al.*, 2011a, 2011b). In fact, with some specific assumptions about the global warming potential of gas it has been suggested that the GHG impact of shale gas might be greater than that of coal on a lifetime basis (Howarth *et al.*, 2011a, 2011b). This perspective has been widely articulated via popular media (e.g., Soraghan, 2011; McDonald, 2011).

Debate regarding this issue has been added to by research published by NOAA scientists (Petron *et al.*, 2012) that studied methane and other fugitive GHG levels in air samples taken in Colorado's Denver-Julesburg oil and gas basin. Their results suggest that fugitive emissions in Colorado's Weld County during 2008 amounted to 3.8% of the county's total gas production that year. The study area, the Denver-Julesburg Basin is a tight sandstone formation that produces appreciable amounts of both gas and oil. In 2008, the year of the study, there were 850 tight gas wells and 1583 oil/condensate wells drilled in the Denver-Julesburg area (HPDI, 2012). An important point regarding the study is that it assessed fugitive emissions levels from the entire gas and oil production system in the basin, which includes many complex upstream and midstream systems widely known as fugitive emissions sources including gathering pipelines, compressor station and condensate tanks (EPA, 2012a; EPA, 2011). Nevertheless, some have interpreted the NOAA analysis as a quantification of fugitive emissions resulting from hydraulic fracturing alone (Tollefson, 2012).

The conclusions of Howarth *et al.* (2011b), have been questioned by some analysts (DOE, 2011; Cathles *et al.*, 2012), and several groups working on the topic have come to different conclusions regarding the relative GHG impact of shale gas. Burnham *et al.* (2011) concludes that the life-cycle GHG emissions from shale gas are slightly less than that of conventional gas, Weber *et al.*, (2012) suggest they are approximately equal, while Jiang *et al.* (2011), Stephenson *et al.* (2011) both conclude that shale gas has a life-time GHG impact that is slightly higher than that of conventional gas. All of these groups do however conclude that the GHG impact of electricity generated using shale gas is significantly less than that of generated with coal. Howarth *et al.*, stand by their conclusions (Howarth *et al.*, 2012), pointing out the significant upward revision in EPA estimates of fugitive emissions from unconventional wells in the EPA's 2011 inventory (EPA, 2011). Their conclusions are also supported, at least in the case of Barnett shale wells, by the analysis in Hultman *et al.* (2011).

3. ANALYSIS

Analysis of this controversy begins with quantification of potential emissions produced during well flowback. This requires knowledge of the duration of the flowback stage, and the rate of gas production during that period. The EPA assumes that the flowback period lasts from 3 to 10 days (EPA, 2011). A recent industry-sponsored survey suggests 3 to 8 days (ANGA, 2012). The analysis of Howarth *et al.*, (2011a) assumes 9-days for the wells in the Barnett shale and 10 days in the Haynesville shale. Here we use a 9-dayflowback period for wells in each of the major shale plays. Although it is certain that flowback durations vary from well to well, our 9-day assumption is at the conservative end of the reported range. Measured data on the rate of flowback from Haynesville shale wells reported by Fan *et al.* (2010) shows that within 9-10 days, the level of fluid production falls by ~75%, and this confirms that 9 days is a reasonable estimate. We assume that gas production during flowback from a given well can be modeled as ramping linearly from zero at flowback initiation to the peak recorded production rate for that well at flowback completion. This assumption is supported by data presented during a recent EPA workshop (EPA, 2012b), and by both simulation results and recorded gas production rates during the flowback of shale wells reported by Fan *et al.* (2010). Integrating this production profile over the 9-day flowback period yields the potential fugitive emissions estimate for each well.

In this report we assess the level of fugitive GHG emissions resulting from the hydraulic fracturing of 3,948 horizontally drilled shale gas wells brought online in the U.S. during 2010 (HPDI, 2012), assuming a number of gas handling scenarios, which involve different levels of venting, flaring and gas capture. **Table 1** shows the potential emissions estimates assuming the mean well peak production rates in each shale play for 2010.

Table 1. Per-well hydraulic fracturing-related potential fugitive emissions from 2010 vintage U.S. horizontal shale gas wells (Source: Authors' calculations based on HPDI 2012).

Per-well potential emissions: ($1 \times 10^3 m^3$ natural gas)	Barnett	Fayetteville	Haynesville	Marcellus	Woodford
Mean:	**273**	**296**	**1,177**	**405**	**487**
P80:	385	409	1,538	573	685
P50:	234	285	1,108	342	413
P20:	138	167	754	195	230

The table also illustrates the substantial well-to-well variability in potential emission levels by showing the estimates for the 20th, 50th and 80th percentile peak production rates. The peak production rate data underlying the values reported in Table 1 can be seen in Table A1 of the Appendix. The variation in initial well productivity within and between the shale plays is driven in large part by underlying geological, geo-mechanical, geo-chemical and petrophysical characteristics of the shale formations. Reservoir pressure, total organic content, thermal maturity, porosity and other factors can all differ within and between plays, and this in turn results in well-to-well variation in productivity (Jarvine *et al.*, 2007; Curtis *et al.*, 2012; Hammes *et al.*, 2011, Baihly, *et al.*, 2010). Aggregating the data in Table 1 for the total number of wells brought online in 2010 yields an overall estimate of hydraulic fracturing-related potential fugitive emissions from the five plays of 902 Gg CH_4. The details of this aggregation are shown in **Table 2**. For comparison, the EPA GHG inventory for the upstream gas sector estimates total 2010 fugitive emissions of 6,002 Gg CH_4.

Table 2. Total hydraulic fracturing-related potential fugitive emissions from U.S. shale gas wells brought online in 2010 (Source: Authors' calculations based on HPDI 2012).

	Barnett	**Fayetteville**	**Haynesville**	**Marcellus**	**Woodford**	**All Plays**
Mean per-well potential fugitive emissions: (1×10^3 m^3 of natural gas)	273	296	1,177	405	487	—
# of horizontal wells	1,785	870	509	576	208	3,948
Total potential fugitive emissions: (1×10^6 m^3 of natural gas)	487	257	599	234	101	1,678
Total potential fugitive methane emissions: (Gg CH_4)	**262**	**138**	**322**	**125**	**54**	**902**

It is useful to compare the per-well potential emissions from Table 1 to the estimated ultimate production from wells in each play. There is appreciable uncertainty regarding the level of ultimate recovery that can be expected from shale wells. Much of this is due to the limited production history of the shale resource and, as yet, not well understood mechanisms of production in ultra-low permeability reservoirs (Anderson *et al.*, 2010, Lee *et al.*, 2010). To account for this uncertainty we assume two well production lifetimes in this analysis; the commonly assumed 30-year lifetime, and a more conservative 15-year lifetime. It is important to acknowledge though that there is legitimate debate ongoing regarding whether the productive lifetimes of these wells may in fact be appreciably shorter than even our 15-year case (Berman, 2012; Hughes, 2011). The results of the comparison between potential emissions produced during flowback and estimates of ultimate recovery based on 30- and 15-year producing lifetimes are shown in **Table 3**. The results indicate that in most shale plays, hydraulic fracturing-related potential fugitive emissions represent 0.4-0.6% of a well's estimated ultimate recovery. In the Haynesville, the ratio is higher at 0.8–1%, owing to the high initial production and production decline rates in that play, which are due to that particular shale's highly over-pressured reservoir (Baihly, 2010). Should it become clear that shorter lifetimes are more representative, then the ratio of potential emissions to ultimate recovery will increase, though not proportionally as shale wells tend to be most productive during their early lives. Details of actual production dynamics from the ensemble of shale wells drilled since 2005 can be found in section A2 of the Appendix.

Table 3. Shale gas hydraulic fracturing-related potential fugitive emissions as a percentage of estimated ultimate recovery assuming mean well production performance rates and 30-year and 15-year producing lifetimes (Source: Authors' calculations based on HPDI, 2012).

	Barnett	**Fayetteville**	**Haynesville**	**Marcellus**	**Woodford**
30-year lifetime	0.39%	0.39%	0.78%	0.39%	0.39%
15-year lifetime	0.54%	0.52%	0.99%	0.53%	0.52%

The proportions of the potential fugitive emissions that are vented, flared, or captured and sold via a reduced emission "green" completion determine the actual GHG intensity of shale gas-related hydraulic fracturing. In this analysis we use specific GHG intensities for venting, flaring and reduced emission completions of 13.438 kg CO_2e, 1.714 kg CO_2e and 1.344 kg CO_2e respectively, based upon a 100-year Global Warming Potential (GWP) for CH_4. Schindell et al, (2009) argue that the use of a 100-year integration period underestimates the actual warming impact of CH_4 and suggests that a higher GWP factor, based on a 20-year integration period be used instead. Because the various GHGs have different lives in the atmosphere (e.g., on the scale of decade for CH_4 but centuries for CO_2 and thousands of years for some other GHG gases), the Intergovernmental Panel on Climate Change (IPCC, 2007) provides this factor for 20-, 100-, and 500-year integration periods and uses 100-year GWPs. MIT (2011) argues that 20-year GWP would emphasize the near-term impact of methane but ignore serious longer-term risks of climate change from GHGs that will remain in the atmosphere for hundreds to thousands years. For a comparison, the specific GHG intensities of venting, flaring and reduced emissions completions assuming a 20-year GWP for CH_4 are detailed in section A3 of the Appendix.

Significant opaqueness surrounds real world gas handling practices in the field, and what proportion of gas produced during well completions is subject to which handling techniques. Diverse opinions on this question exist even within the gas industry. Some analysts state that gas companies have had a policy of not investing in gas conservation measures due to the low rate of return. By contrast, an industry survey of unconventional gas producers has suggested that reduced emission completions are being used on more than 90% of shale wells completions, and that in the case of those wells not subject to a reduced emissions completion, the duration of flowback is rarely more than 3 days (ANGA 2012). Some of the contemporary analysis on shale gas-related fugitive emissions has not attempted to account for the impact of real world gas handling field practice. For example, in Howarth *et al.* (2011b) it is assumed that all potential fugitive emissions are vented. This is an unreasonable assumption, not least because some producing states have regulation requiring flaring as a minimum gas handling measure. The EPA in its quantification of fugitive emissions does assume a certain proportion of gas is flared (EPA, 2011; EPA, 2012a); however, it does not separate fugitive emission from shale wells with those from tight and other unconventional gas sources. Furthermore, the EPA analysis does not adequately assess gas capture levels, particularly in regions where flaring is required.

We assess several gas handling scenarios, ranging from the assumption that all potential emissions are vented (Howarth *et al.*, 2011b), to that suggested by a gas industry group in which 93% of potential fugitive emissions are captured (ANGA, 2012). However, our main estimate of actual fugitive emissions is based on a "current field practice" gas-handling scenario, where 70% of potential fugitives are captured, 15% vented, and 15% flared. This we believe is a reasonable representation of current gas handling practices in the major shale plays (EPA, 2012b) (Further discussions of gas handling scenarios are presented in section A3 of the Appendix). **Table 4** contrasts the level of per-well actual fugitive emissions based upon the assumption of the "current field practice" scenario and the "all vented" scenario. Compared to the all-vented analysis (Howarth *et al.*, 2011b), which reports emissions from Barnett as 252 Mg CH_4/well (or 370,000 m^3 CH_4) and 4,638 Mg CH_4/well (6,800,000 m^3 CH4) for Haynesville, our mean estimates are 35.1 Mg CH4/well and 151.3 Mg CH_4/well, respectively.

Table 4. Per-well actual fugitive GHG emissions from shale gas-related hydraulic fracturing in 2010 (Source: Authors' calculations based on HPDI 2012).

	Barnett	**Fayetteville**	**Haynesville**	**Marcellus**	**Woodford**
Per-well GHG emissions: Mg CH_4/well (related CO_2 emissions are added based on 100-yr CH_4 GWP)					
All Vented	146.7	159.1	632.7	217.7	261.8
Current Field Practice	35.1	38.0	151.3	52.1	62.6

Beyond regulation, the methods selected to handle gas during well completions in the field are driven by economics. In the case of conventional gas wells, the volumes of potential emissions produced during completion are very low. According to the EPA, on average, 1,040 m^3 CH4 (36.36 Mcf) are produced by a conventional well completion (EPA, 2010). The economic value of this gas would certainly not justify the use of a reduced emission "green" completion. By contrast, the level of potential emissions from shale wells is very large. In Howarth *et al.* (2011b) it is stated that 3.2% of the estimated ultimate recovery from a Haynesville shale well is produced during flowback. In that case, 3.2% of estimated ultimate recovery amounts to 6,800,000 m^3 CH4. This is a very considerable amount of gas and assuming a conservative long-run wellhead gas price of $4.00/MMBtu (MIT, 2011; NYMEX, 2012; EIA, 2012), simply venting, or indeed flaring this gas would amount to a revenue loss of $1.2 million for the operators. Admittedly, this is an extreme example since the performance of the particular Haynesville well in question is not representative of a typical Haynesville well; however, even when considering mean shale well performance data, the value of gas produced during flowback is substantial, and likely to warrant the cost of capture. Based on our mean estimates of potential emissions shown in Table 1, the gross values of capturing this gas using a reduced emission completion ranges from $39,000 for a Barnett well to $166,000 for a Haynesville well. The aggregate gross value of the gas produced during flowback from the 3,948 shale wells considered in this study amounts to $320 million. Capturing potential emissions is not without cost, of course, but these costs appear to be relatively modest (A detailed discussion of the variability in the gross value of gas produced during flowback, and the costs associated with reduced emission completions can be found in section A4 of the Appendix.). If the cost of reduced emission completion is $1,000 per day as stated by Devon (2008), 95% of the 2010 Barnett wells yielded positive net revenues, i.e. operators added to the value of their wells by capturing the potential fugitive emissions. Even at twice this reported capture cost, $2,000 per day, 83% of the 2010 Barnett wells would still positive net revenues, and this trend is repeated in the all the other shale plays. The results of a sensitivity analysis exploring the impact of reduced emissions completion costs and gas price variation on the 2010 Barnett shale well ensemble are shown in Figures A5 and A6 of the Appendix.

4. CONCLUSIONS

Taking actual field practice into account, we estimate that in 2010 the total fugitive GHG emissions from U.S. shale gas-related hydraulic fracturing amounted to 216 Gg CH_4. This represents, 3.6%, of the estimated 6,002 Gg CH_4 of fugitive emissions from all natural gas production-related sources in that year (EPA, 2012a; EPA, 2012b). The entire natural gas value chain is estimated to have produced 10,259 Gg CH_4 of fugitive emissions in 2010, or about 3.1% of the Nation's total GHG inventory (EPA, 2012a; EPA, 2012b). Thus under a goal of GHG reduction it is clear that increased efforts must be made to reduce fugitive losses from this system. However, it is also clear is that the production of shale gas and specifically, the associated hydraulic fracturing operations have not materially altered the total GHG emissions from the natural gas sector. Furthermore, for the vast majority of contemporary shale gas wells, the revenues gained from using reduced emissions completions to capture the gas produced during a typical flowback cover the cost of executing such completions.

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APPENDIX[1]

Contents

A1. SHALE GAS PRODUCTION GROWTH IN THE UNITED STATES

Natural gas production in the United States has undergone a renaissance over the past 5–6 years as a result of shale gas (Deutch, 2011). Between 2005 and 2010 the contribution from shale gas to total U.S. marketed gas production rose from less than 2% to more than 20%. Based upon EIA data, 2011 has set an all time record for U.S. production as the result of shale gas growth, with total daily dry output for the first ten months of the year averaging 1.77 Gm^3/day (62.7 Bcf/day).

The remarkable shale gas production levels seen over the past number of years have been supported by a relatively small number of plays, the main ones being the Barnett shale, in Texas' Fort Worth basin, the Fayetteville and Woodford shales of the Arkoma basin in Arkansas and Oklahoma, the Haynesville shale on the Texas Louisiana boarder, the Marcellus shale in the Appalachian basin, and of late the Eagle Ford shale located in southwest Texas. **Figure A1** illustrates the growth in gas output from these shale gas plays since 2000. Until 2009 the overwhelming majority of total U.S. shale gas production came from the Barnett shale; however, in the last two years that situation has changed and production from other plays, particularly the Haynesville and Marcellus is now growing rapidly.

A2. VARIABILITY IN SHALE WELL PRODUCTION PERFORMANCE

The shale plays currently being developed in the U.S. do not constitute a homogenous resource. Each play has its own set of particular geological, geo-mechanical, geo-chemical and petrophysical characteristics, and variability in factors including reservoir pressure, total organic content, thermal maturity, porosity, the presence of natural fractures along with a lack of knowledge regarding shale rocks' fundamental production mechanisms means that the performance of individual wells can differ substantially both within and between plays (Jarvine *et al.*, 2007; Curtis *et al.*, 2012; Hammes *et al.*, 2011; Baihly *et al.*, 2012).Two metrics widely used in describing shale well performance are the initial production (IP) rate and the production decline rate. Together these combine to determine the ultimate recovery (UR) from a well.

The IP rate variability among horizontal wells brought on production in the five most active U.S. shale gas plays in 2010 is given in **Table A1**. Reviewing the data in the table reveals the

[1] This is an appendix to O'Sullivan and Paltsev (2012): Shale Gas Production: Potential versus Actual GHG Emissions, MIT Joint Program on the Science and Policy of Global Change *Report 230* (http://globalchange.mit.edu/files/document/MITJPSPGC_Rpt230.pdf)

extent of both the intra and inter-play well-to-well IP rate variability. In each play the P80 IP rates are 2–3X the P20 rates, while between plays the mean IP rates vary by up to 4.3X. Similar trends can also be observed in IP rate data for prior years.

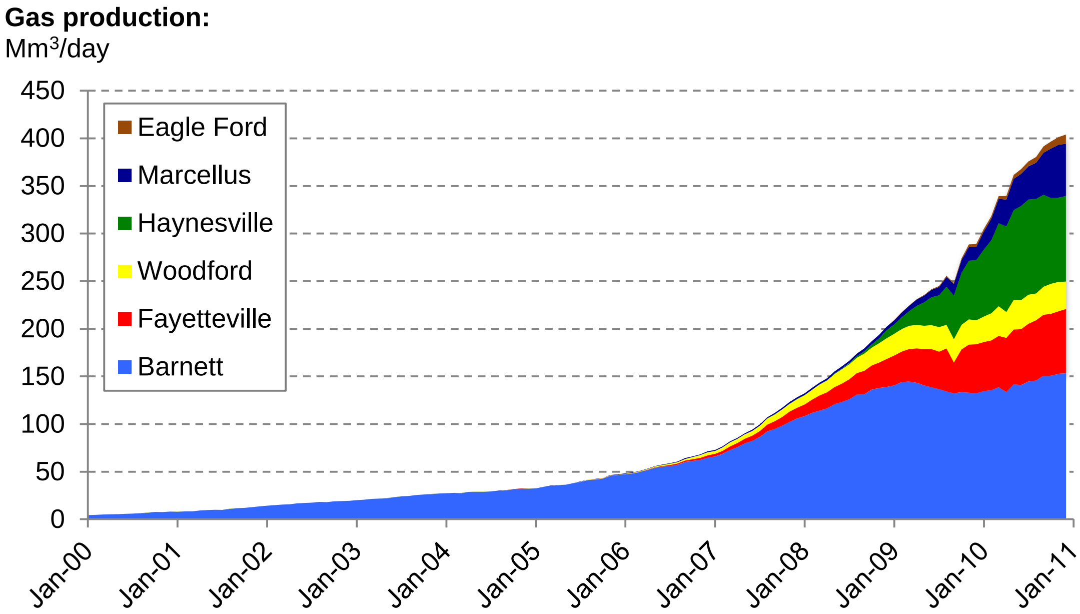

Figure A1. Growth in natural gas production from U.S. shale plays between 2000 and 2010 (Source: HPDI, 2012).

Table A1. IP rate variability of the horizontal wells brought on production during 2010 in the Barnett, Fayetteville, Haynesville, Woodford and Marcellus shale plays (Source: Authors' calculations based on HPDI, 2012).

		IP Rate: 1×10^3 m^3/day			
Shale Play	**# of H. Wells**	**Mean**	**P80**	**P50**	**P20**
Barnett	1,785	60.6	85.5	52.1	30.6
Fayetteville	870	65.7	90.8	63.4	37.1
Haynesville	509	261.5	339.6	246.2	167.5
Woodford	208	108.1	152.3	91.7	51.2
Marcellus	576	90.0	127.4	76.1	43.3

The Barnett shale play provides an excellent basis for examining this year-to-year IP rate variability due to its relatively longer production history and larger inventory of well. **Figure A2** plots the IP rate cumulative probability functions for each vintage of horizontal wells drilled in the Barnett from 2005 to 2010. Each vintage displays the well-to-well IP rate variability described above, however, it is also clear that the on average, IP rates have been increasing incrementally year-on-year. In 2005, the mean, P90 and P10 IP rates for the 720 horizontal wells that were brought on production were 48,500, 93,050 and 14,300 m^3/day respectively. By 2010 those same figures had increased to 60,700, 110,900 and 21,500 m^3/day. Many factors play a role in this IP rate shift; however, increased horizontal well lengths and more effective fracturing are likely to be some of the most important.

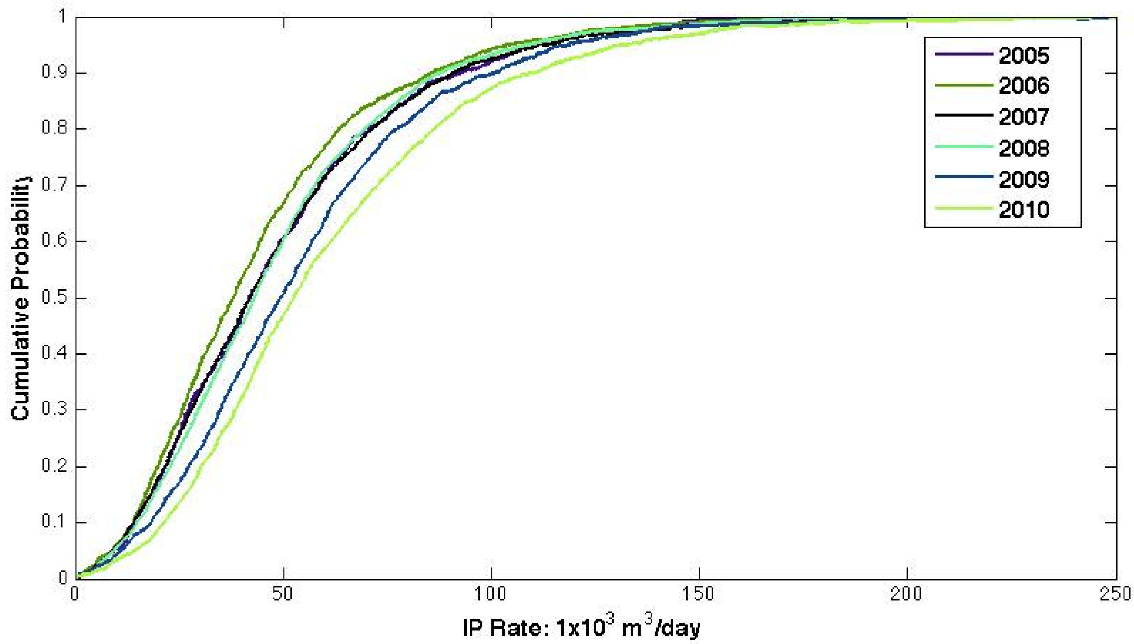

Figure A2. Cumulative probability functions for initial production rates of horizontal wells drilled in the Barnett shale from 2005 to 2010 (Source: HPDI, 2012).

The rate at which a well's gas production changes over time is described by the well's decline characteristic or "type curve." Data on shale well decline characteristics is still sparse due to the limited time most wells have been producing. However, the data that is available reveals some interesting trends. The first is that in general, shale well output tends to drop by 60% or more from the IP rate level over the first 12 months. The second is that the available longer-term production data suggests that levels of production decline in later years are moderate, often less than 20% per year. **Figure A3** shows the normalized decline characteristics for each vintage in the Barnett shale from 2005 to 2010. Although there is some variation, overall, the normalized decline characteristics have been very similar year-to-year.

All the shale plays currently in production have qualitatively similar decline characteristics, i.e. significant production decline during the first year of production followed by more moderate rates of decline in subsequent years. Nonetheless, there are meaningful differences between plays as shown in **Figure A4**, which plots the normalized 2009 decline characteristics of the Barnett, Fayetteville and Haynesville plays. The Barnett and Fayetteville plays have relatively similar year 1 decline rates of 55–60%.

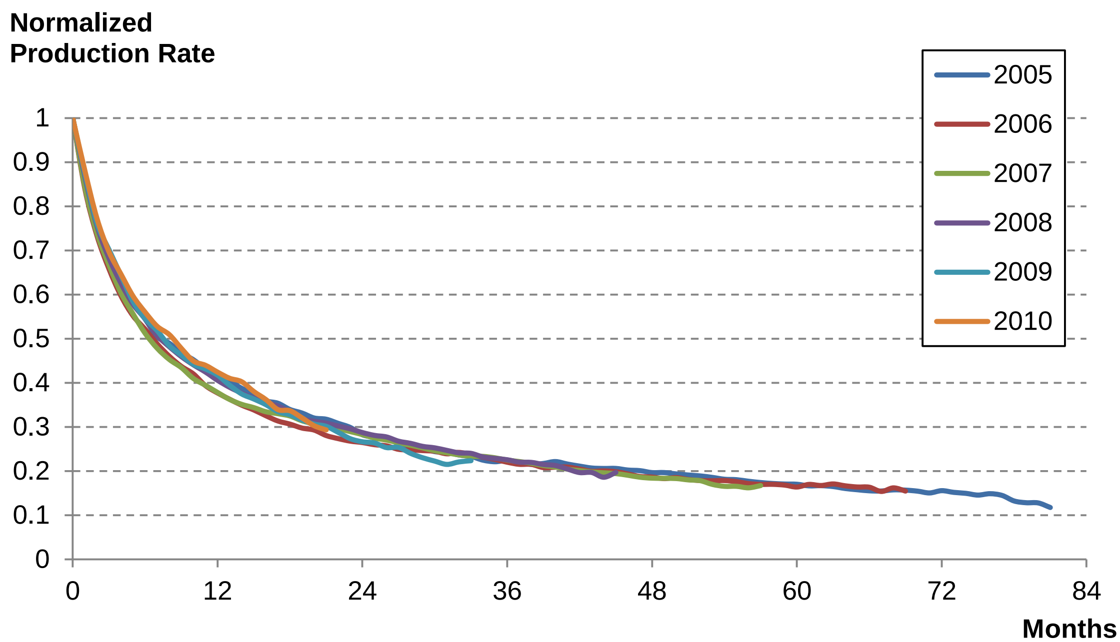

Figure A3. Normalized production decline characteristics for Barnett shale well vintages from 2005 to 2010 (Source: HPDI, 2012).

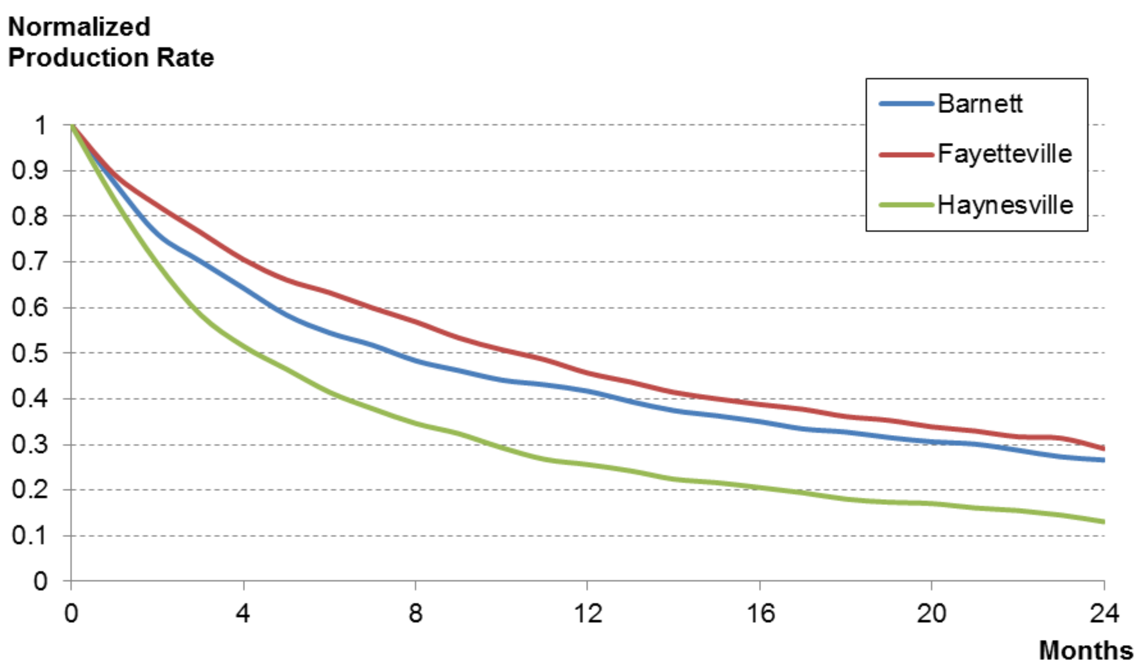

Figure A4. Normalized production decline characteristics for 2009 vintage horizontal wells in the Barnett, Fayetteville and Haynesville shale plays (HPDI, 2012).

The Haynesville decline characteristic is different, with a year 1 production rate decline of ~75%. Understanding the differences in decline characteristics among shale plays is very complex and requires consideration of both reservoir and well completion factors. However, insights do exist regarding the variability. For example, in the case of the Haynesville, its very high year 1 decline rates have been linked to the highly over-pressured nature of the reservoir and the likelihood of pressure dependent permeability resulting in a temporally progressive reduction in gas conductivity (Thompson *et al.*, 2010; Baihly *et al.*, 2010).

Determining how much gas individual shale wells will produce over their lifetime is also a challenging problem muddied by many uncertainties. To date, estimates of shale well UR have been made by combining IP rate data with long-term projections of well production decline characteristics. These decline projections are often extrapolated from shorter-term decline data shown in Figures A3 & A4. These "type curve" methods for estimating shale well UR are controversial as they are based on techniques developed to assess the UR from wells in reservoir boundary dominated flow regimes (Lee *et al.*, 2010; Anderson *et al.*, 2010). The complexity of these issues is beyond the scope of this paper; however, one outcome is that the fitting of shale well decline rate data has in some instances yielded parameters outside the limits suggested as reasonable by the theory, and the practical result of this is that UR estimates based on these type curve methods must be viewed with some caution, particularly in terms of possible overestimation (Lee *et al.*, 2010). Nonetheless, until more data becomes available, the use of type curves at least for aggregate qualitative analysis is not unreasonable. UR estimates based on the type curve method for the 2010 vintage of horizontal wells in the major U.S. shale plays are given in **Table A2**. These URs were calculated assuming both a 30-year well production lifetime, and a more conservative 15-year well lifetime. A 30-year well producing lifetime is widely assumed, particularly by the industry, when estimating shale well UR.

Table A2. Projected horizontal well URs for the major U.S. shale plays based on 2010 well IP rate data assuming 30-year and 15-year production lifetimes (Source: Authors' calculations based on HPDI 2012).

	Estimated UR: 1x10^6 m^3 (30/15 year estimates)			
Shale Play	**Mean**	**P80**	**P50**	**P20**
Barnett	70.8 / 50.9	99.1 / 73.6	59.4 / 45.3	36.8 / 25.5
Fayetteville	76.4 / 56.6	104.7 / 76.4	73.6 / 53.8	45.5 / 31.1
Haynesville	150.0 / 118.9	192.4 / 155.7	141.5 / 113.2	96.2 / 76.4
Woodford	124.5 / 93.4	175.5 / 130.2	107.5 / 79.2	59.4 / 42.45
Marcellus	104.7 / 76.4	147.2 / 107.6	87.7 / 65.1	50.9 / 36.8

A3. GHG INTENSITY OF FLOWBACK GAS HANDLING METHODS

Knowing how gas produced during flowback is handled is necessary to evaluate the actual fugitive emissions from shale well hydraulic fracturing operations. Broadly speaking, three handling options exists; the gas can be vented directly to the atmosphere, it can be flared, or it can be captured and routed to a pipeline. This final process is often referred to as "reduced emissions completion" or "green completion." Of the three methods, venting has the highest GHG intensity, with every 1 m^3 of gas vented resulting in 0.788 m^3 of methane emissions (EPA, 2010). Flaring, when executed correctly is 98% efficient, thus resulting in 0.01–0.02 m^3 of methane emissions per m^3 of natural gas flared (EPA, 2010). Gas capture have the potential to completely eliminate any methane or CO_2 emissions resulting from flowback; however, in practice this is probably not achievable. Data from the EPA suggests that green completions result in the capture of at least 90% of potential methane emissions (EPA, 2010). This is likely an underestimation of the gas captured during well-executed green completions; however, we use it for analysis purposes in this paper.

The specific GHG emissions factors of the three gas handling techniques are given in **Table A3**. These factors were calculated assuming natural gas is composed of 78.8% methane by volume (EPA, 2010). The GHG impact of other constituent gases was ignored. This is a clear simplification particularly considering natural gas often contains some volumes of CO_2; however, it is consistent with the EPA's own methodology and that used by others carrying out similar analysis (Hultman *et al.*, 2011). The methane contribution was converted into CO_2e using both 100- and 20-year methane global warming potentials (GWPs) of 25 and 72 respectively (Solomon *et al.*, 2007). Calculations using both the standard 100-year GWP and the 20-year GWP are shown in order to acknowledge the debate currently occurring regarding which factor should be used when assessing the GHG emissions impacts of natural gas production and use (Howarth *et al.*, 2011a; Howarth *et al.*, 2011b, Cathles *et al.*, in press). A concise summary of the underlying scientific analysis that is cited as part of this debate is provided by Hultman (Hultmen *et al.*, 2011) and concludes that there exists, reasonable alternative perspectives on the issue. The specific emission factors reported in Table A3 reveal the very dramatic impact that assumptions regarding how gas produced during flowback is handled can have on the analysis of GHG footprints. When assuming a 100-year GWP for methane, the difference in the emission factors of cold-venting and green completions is an order of magnitude. Assuming a 20-year GWP, flaring becomes the least GHG intensive method of handling flowback gas.

Table A3. Calculation of emission factors for gas handling techniques, which can be deployed during shale well flowback operations assuming both 100 and 20-year global warming potentials (GWP) (Source: Authors' calculations).

	Venting	Flaring	Gas Capture
CH_4 emitted: kg/1x10^3 m^3 of NG	537.5	10.8	53.8
CO_2 emitted: kg/1x10^3 m^3 of NG	–	1,445.1	–
Total emissions factor (100-yr GWP): kg CO_2e/1x10^3 m^3 of NG	13,438	1,714	1,344
Total emissions factor (20-yr GWP): kg CO_2e/1x10^3 m^3 of NG	38,701	2,219	3,870

To date, attempts to analyze the GHG intensity of shale gas production have relied heavily on information from the U.S. EPA. In particular, EPA analysis that suggests a natural gas emissions factor of 9,175 Mcf per unconventional well completion or workover is widely cited (INGAA, 2008). In this context the term "emissions factor" is misleading. The 9,175 Mcf figure is the EPA's quantification of the volume of natural gas produced during flowback, i.e. the potential emissions, not the actual emissions. The authors suggest that the EPA revise their terminology in future publications and refer to this value as "potential emissions" in order to minimize confusion. As a quantification of "potential emissions" the 9,175 Mcf, or 259,836 m^3 of natural gas per completion appears reasonable, at least in qualitative terms. In comparison to the per-well potential emissions estimates in Table 1, the EPA figure is slightly lower than that for a 2010 mean performance well in the Barnett shale. This would be expected as the EPA figure is derived from data that included not just shale wells, but also lower performance unconventional wells.

The EPA is opaque with regards to defining how potential emissions are handled. This is understandable due to the lack of hard data; however, the agency does attempt to provide some directional guidance. For the purposes of estimating emissions from 2007 U.S. gas well completions and workovers, it assumes that 51% of the gas produced during well flowback is flared and 49% is vented (EPA, 2010). This breakdown is based upon regulation in place in four sample states; Texas, New Mexico, Oklahoma and Wyoming. A 2008 INGAA report (INGAA, 2008) estimated that if a more representative set of states were considered, then the proportion of flowback gas that would require flaring by regulation would fall from 51% to 15%. However, regulation is only part of the gas-handling picture. This is illustrated by the fact that in those states without a mandatory flaring requirement in the EPA's four state analysis, ~70% of the gas produced during flowback was not vented, but in fact captured by green completion operations (EPA, 2011). Additionally, an unknown, but likely similar proportion of the gas produced where flaring was required (as a minimum control) is also likely to have been captured. The reason for this is economic incentive. Where capture is possible due to infrastructure availability, the marginal cost of the process itself is low and operators generate value by doing it. A detailed discussion of green completion economics will be presented in section A4.

The contention that real-world flowback gas handling practices differ appreciably from what regulation alone demands is supported by the results of a 2011 American Natural Gas Alliance (ANGA) survey (Thompson *et al.*, 2010) of field practice. This survey recorded the gas handling approaches used by 8 exploration and production companies across a representative set of U.S. unconventional gas (both shale and tight sands) plays. A total of 1,578 wells were included in the survey. Of these wells, gas was captured during flowback from 1,475 or 93%, 56 wells were flared and 47 wells were vented. Of course the fact that these results are the product of an industry sponsored survey means they are open to question, however, the survey does represent the only large-scale publically reported assessment of current gas handling field practice available. In preparing this paper the authors had extensive discussions with industry, EPA and other relevant groups regarding actual field practice. We have concluded that a reasonable representation of contemporary flowback gas handling field practice in U.S. shale plays would comprise 70% of wells using reduced emissions completions, 15% being flared and 15% being vented (EPA, 2012b).

Table A4. Specific GHG intensities for five flowback gas handling scenarios assuming 100 year and 20 Year CH_4 global warming potentials (GWP) (Source: Authors' calculations).

Flowback GHG intensity: kg CO_2e/m3 of NG	100-Year GWP	20-Year GWP
Scenario 1: 100% vented	13.44	38.70
Scenario 2: 15% flared, 85% vented	11.68	33.23
Scenario 3 51% flared, 49% vented	7.46	20.10
Scenario 4: 93% GC, 4% flared, 3% vented	1.72	4.85
Scenario 5—"Current Field Practice": 70% capture, 15% flared, 15% vented	3.21	8.85

To illustrate how assumptions regarding gas handling impact on the GHG intensity of shale gas-related hydraulic fracturing we take the potential emissions data from Tables 1 & 2, and calculate the associated actual emissions assuming five gas handling scenarios (Deutch, 2011); all potential emissions are vented as assumed in (Howarth *et al.*, 2011a; Jacoby *et al.*, 2012), a case where 15% of gas is flared and the remainder is vented per (INGAA, 2008; IEA, 2012), the regulatory case where 51% of gas is flared and the remainder is vented per EPA; (4) the ANGA survey case with 93% capture, 4% flared and 3% vented, and (5), a "current field practice" case, with 70% capture, 15% flared and 15% vented. **Table A4** shows the GHG intensities in kg CO_2e/m^3 associated with each of the gas handling cases assuming both a 100-year and 20-year GWP factor for CH_4

Table A5. Mean per-well actual emissions from shale well hydraulic fracturing operations in 2010 (Source: Authors' calculations based on HPDI 2012).

	Barnett	Fayetteville	Haynesville	Marcellus	Woodford
Per-well GHG intensity: Mg CO_2e/well (100 year CH_4 GWP)					
100% vented	3668.5	3977.6	15816.4	5442.3	6544.2
15% flared, 85% vented	3188.4	3457.1	13746.5	4730.1	5687.8
51% flared, 49% vented	2036.2	2207.8	8778.8	3020.7	3632.4
ANGA Survey	469.9	509.5	2026.1	697.2	838.3
Current field practice	877.3	951.2	3782.2	1301.4	1564.9
Per-well GHG intensity: Mg CO_2e/well (20 year CH_4 GWP)					
100% vented	10565.4	11455.5	45551.1	15673.9	18847.4
15% flared, 85% vented	9071.5	9835.7	39110.3	13457.6	16182.4
51% flared, 49% vented	5486.0	5948.2	23652.1	8138.6	9786.4
ANGA Survey	1323.8	1435.3	5707.3	1963.8	2361.5
Current field practice	2415.3	2618.7	10413.0	3583.1	4308.5

The specific GHG intensities shown in Table A4 reveal the importance of gas handling assumptions. There is 7.8X difference in intensity depending upon whether you assume all potential emissions are vented (Scenario 1), or handled according to the ANGA survey (Scenario 4) assuming a 100 year CH_4 GWP. Coupling the specific GHG intensity factors in Table A4 with the volumes of potential emissions from Tables 1 & 2 enables the evaluation of actual emissions associated with shale well flowback in 2010 for different gas handling scenarios. The per-well actual emissions are shown in **Table A5**, with the aggregate actual emissions in **Table A6**.

Table A6. Total actual emissions from 2010 shale well hydraulic fracturing operations. (Source: Authors' calculations based on HPDI, 2012)

	Barnett	Fayetteville	Haynesville	Marcellus	Woodford	Total
Total GHG intensity: Tg CO_2e (100 year CH_4 GWP)						
100% vented	6.5	3.5	8.1	3.1	1.4	23
15% flared, 85% vented	5.7	3.0	7.0	2.7	1.2	20
51% flared, 49% vented	3.6	1.9	4.5	1.7	0.8	13
ANGA Survey	0.8	0.4	1.0	0.4	0.2	3
Current field practice	1.6	0.8	1.9	0.7	0.3	5
Total GHG intensity: Tg CO_2e (20 year CH_4 GWP)						
100% vented	18.9	10.0	23.2	9.0	3.9	65
15% flared, 85% vented	16.2	8.6	19.9	7.8	3.4	56
51% flared, 49% vented	9.8	5.2	12.0	4.7	2.0	34
ANGA Survey	2.4	1.2	2.9	1.1	0.5	8
Current field practice	4.3	2.3	5.3	2.1	0.9	15

A4. ECONOMIC MOTIVATION FOR FLOWBACK GAS CAPTURE IN SHALE PLAYS

As shown in Table A4, the gas handling methods used to during flowback have a dramatic impact on the GHG intensity of the process. Because of the volumes of gas involved, particularly in the case of contemporary shale wells, the extensive or exclusive use of venting would results in the process having a very high GHG intensity. By contrast, the extensive use of flaring and particularly capture result in much more benign emission levels; however, both flaring and capture are not without their operation challenges. Capture in particular requires gas gathering facilities to be present at the well pad during flowback, something that is not always practical.

Traditionally, gas exploration and development involved an appreciable amount of trial and error or "wildcatting," whereby single or small numbers of wells were drilled in a prospective area without a high level of certainty that those wells would ultimately prove to be commercial. With this approach gas gathering systems would only be built after a well was completed. As a result capture was rarely practical or necessary for that matter as fracturing was less widely used. Contemporary shale gas development takes place in a very different manner. Often described as a "manufacturing process," shale plays are developed in a relatively systematic manner made possible by the extensive and contiguous nature of the producing formations, and the relative assurance that any given well will produce gas. This relative a priori assurance regarding production coupled with the fact that multi-well pads (often six or more well being drilled horizontally from one surface location) are now standard practice means that gathering infrastructure is in many cases being built in parallel or even ahead of actual well drilling and hydraulic fracturing operations.

Operators in shale plays have a significantly higher economic incentive to have gathering facilities in place as wells are being completed than is the case in conventional plays. The assurance that the well will most likely produce gas means that by having gathering available as soon as a well is ready to go online saves the operators the carry costs associated with a completed but stranded well, and this boosts the present value of any given well. Furthermore, having gathering facilities in place also enables operators market the significant volumes of gas that will be produced during flowback. This is important as it means that producers are financially incentivized to minimize fugitive emissions.

The current debate regarding the GHG intensity of flowback operations has relied heavily on assumptions regarding regulation. Considering regulation is of course necessary in any such analysis; however, it is not sufficient. To fully assess the situation, one must also consider the economics of the relevant gas handling techniques, as seen from the gas operators' perspective. Both venting and flaring destroy value. Clearly though, if the present value of these approaches is higher (or less negative) than capturing the gas they will be chosen. For low performance unconventional tight sands wells it is certainly possible that the typical volumes of gas produced during flowback are too small to warrant gas capture. However, in the case of contemporary shale wells the situation is entirely different. **Table A7** shows the mean per-well and total value of gas produced during shale well flowback operations in 2010 assuming a conservatively low long-term gas price of \$4.00/Mcf (\$141.24 per thousand m^3) (MIT, 2011).

Table A7. Gross value potential of gas produced during flowback operations in the major U.S. shale plays during 2010 (Source: Authors' calculations).

	Barnett	Fayetteville	Haynesville	Marcellus	Woodford	All Plays
Per-well value: $k	38.6	41.8	166.2	57.2	68.8	–
# of horizontal wells	1,785	870	509	576	208	3,948
Total value: $M	68.8	36.4	84.6	32.9	14.3	237.1

Overall, more than \$237 million dollars-worth of gas was produced during shale well flowback operations in 2010, or just over \$60,000 of gas per well. These are significant cash flows and their importance to the overall economics of an individual well should not be overlooked, particularly as these cash flows occur in year 0 and so are not subject to any time-value-of-money discounting. Of course gas capture is not free, and the costs must be included in the analysis. These authors define the cost of gas capture as the amortized capital cost along with operating costs, or more typically the rental costs of a green completion separator unit and accompanying crew. These units are in essence very high capacity versions of the multi-phase separation systems that are permanently installed at producing well. They are specifically designed to handle the much higher volumes of water and solids that flow during flowback and are typically skid or trailer mounted. The costs of gas gathering infrastructure are not considered in the assessment of the gas capture economics. These facilities are a sunk cost as they must be in place to get gas to market regardless of whether flowback gas captured, vented or flared.

The cost of green completion services differs somewhat by play due to the different equipment specifications needed to handle differing levels of flowback. Devon Energy reports a per-well per-day cost of $1,000 for green completion services in the Barnett shale (EPA, 2010). This figure is reasonable, and also representative of the costs in the Fayetteville shale. Correspondence with operators in the higher performance plays such as the Marcellus shale have indicated that flowback gas capture costs of between $2,000 and $3,000 per-well per-day. To establish a conservative estimate of the value generation potential of gas capture, slightly higher per-well per-day capture costs were assumed. $2,000 for the Barnett and Fayetteville shales, $3,000 for the Marcellus and Woodford plays and $6,000 for the very high volume wells in the Haynesville. Coupling these costs with the gross revenue figures from Table A7 enables the net value potential of green completions to be calculated. The results of this are shown in **Table A8**.

Table A8. Net value potential of gas produced during flowback operations in the major U.S. shale plays during 2010 (Source: Authors' calculations).

	Barnett	**Fayetteville**	**Haynesville**	**Marcellus**	**Woodford**	**All Plays**
Per-well gross revenue: $k	$38.6	$41.8	$166.2	$57.2	$68.8	–
Per-well capture cost: $k	$18.0	$18.0	$54.0	$27.0	$27.0	–
Per-well net value of capture:	20.6	23.8	112.2	30.2	41.8	–
# of horizontal wells	1,785	870	509	576	208	3,948
Total net value potential of gas capture: $M	$36.7	$20.7	$57.1	$17.4	$8.7	$140.6

The results in Table A8 show that gas capture generates value in all plays. For an average well in most shale plays the net additional value will be anywhere from $20,000 to $40,000. In the Haynesville the net value per well of capture will be over $100,000. Given 2010 activity levels, the total net value of gas capture is just over $140 million. As discussed earlier, it is not practical to expect the use of green completion techniques on 100% of shale wells; however, assuming that 70% of shale wells are green completed, this still represents almost $100 million dollars in annual value generation as $4.00/Mcf gas. The preceding analysis of gas capture economic attractiveness makes a number of assumptions, albeit reasonable ones regarding the wellhead gas price and the cost of capture. Sensitivity analysis on these variables provides further insight. **Figures 5** shows what percentage of the 2010 Barnett well population would yield positive net revenue from gas capture assuming the cost of the completions was $1,000, $2,000 and $3,000 dollars per day for a 9 day flowback period, at $4.00/Mcf wellhead gas price.

At the $1,000 per day green completion cost quoted by Devon Energy (*21*), 95% of wells generated positive net revenue, i.e. the value of the gas captured and sold was more than the cost of capture. At our more conservative $2,000 per day case 83% of all wells still generated positive revenue, and even assuming a very high cost of $3,000 per day, 64% of wells generated positive net revenues. **Figure A6** shows the impact of varying gas price on the green completion economics of the same wells assuming a fixed completion cost of $2,000 per day.

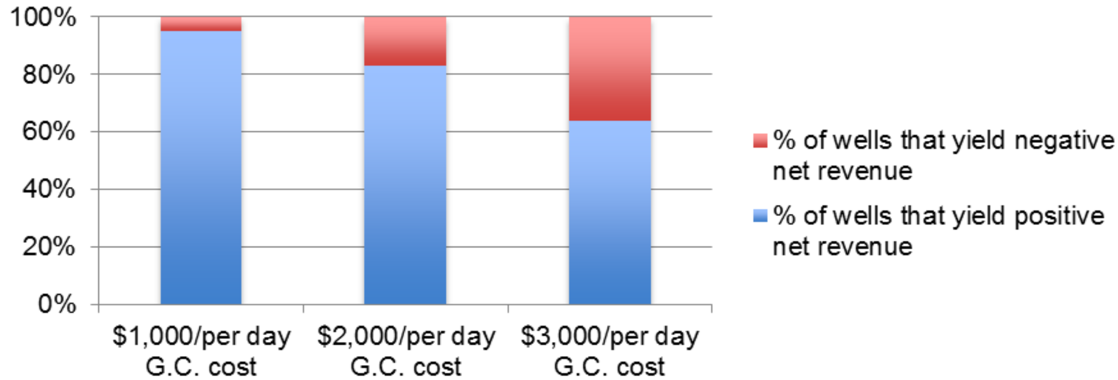

Figure A5. Percentage of 2010 Barnett shale wells for which gas capture yields positive and negative net revenues assuming a wellhead gas price of $4.00/Mcf and gas capture costs of $1,000, $2,000 and $3,000 per day (Source: Authors' calculations).

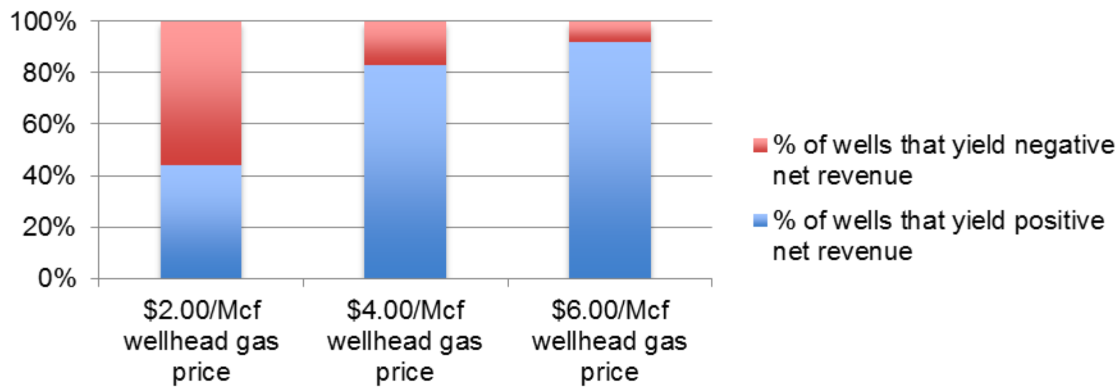

Figure A6. Percentage of 2010 Barnett shale wells for which gas capture yields positive and negative net revenues assuming wellhead gas prices of $2.00/Mcf, $4.00/Mcf and $6.00/Mcf and a capture cost of $2,000 per day for a 9 day flowback period. (Source: Authors' calculations).

At $2.00/Mcf, 44% of the wells generate positive revenue, while at $6.00/Mcf, 92% of the wells were in the black. An important point to note is that although natural gas prices in the U.S. during late 2011 and early 2012 have been between $2.50–3.00/Mcf range, these prices are not indicative of the likely long-term equilibrium price in the U.S. market. The 2011 EIA Annual Energy Outlook (U.S. EIA, 2011) projects wellhead gas prices of over the coming 5 year to be in the $4.00–$4.50/Mcf range, while the 2011 MIT Future of Natural Gas study (MIT, 2011), projects gas prices over the same period to be in the \$5.00–\$5.50/Mcf range. Given these projections, we feel that the use of a \$4.00/Mcf assumption in the economic analysis of green completions is conservative.

The results of the sensitivities shown in Figures A5 and A6 reiterate the point that shale well flowback gas capture is economically attractive to operators. This is so for the vast majority of well even in lower performance shale plays like the Barnett, and even under higher than reasonable costs and lower than likely gas price scenarios.

A5. REFERENCES

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