Venting and Leaking of Methane from Shale Gas Development: Response to Cathles et al.

Electronic Supplemental Materials

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Calculations and Information in Support of Table 1:

To compare methane emissions from various studies in Table 1 of our accompanying paper, we normalized the emissions to the heat content of gas expressed as the Lower Heating Value (LHV). LHV is the standard internationally, but many recent papers instead used the higher heating value (HHV), a common convention in the U.S. For the LHV convention, the mass of methane per energy is 15 g C of methane per MJ (Hayhoe et al. 2002), corresponding to 0.028 m^3 MJ^{-1} of natural gas under standard conditions. Converting from HHV to LHV reduces the apparent energy content of natural gas by approximately 10%. We also express emissions as g C of methane, rather than mass of methane or mass of carbon dioxide equivalents (gCO_2-e), using the ratio of molar masses (12 g for C, 16 g for CH_4, and 44 g for CO_2). When emissions were reported in gCO_2-e, we converted to g C of methane using the global warming potentials employed in those studies.

Below we provide detailed information on our use of information from each of the studies in Table 1, presented chronologically by date of publication.

Hayhoe et al. (2002)

Hayhoe et al. (2002) reported a "best estimate" for emissions for conventional gas as 0.76 kg CH_4 GJ^{-1} (expressed as LHV) based on a 3.5% loss for the conventional natural gas life-cycle, or 0.57 g C MJ^{-1} of methane. This is higher than the estimate by EPA (2011a) for conventional gas, but compares very well with the mean estimate from Howarth et al. (2011). Note that Hayhoe et al. (2002) reported a very wide possible range that fully encompasses all other estimates given in Table 1.

Jamarillo et al. (2007)

Jaramillo et al. (2007) assumed a total life-cycle methane loss of 1.07% of conventional gas production. The authors reported 2003 North American production at 764 x 109 m^3 (27 Tcf) with average heat content (HHV) of 0.026 m^3 MJ^{-1} (1030 Btu cf^{-1}), gas composition of 96% methane, and a methane density of 679 g m^3 (0.0424 lb cf^{-1}). Using these assumptions, the 1.07% loss equates to 0.15 g C MJ^{-1} as methane (LHV). As discussed in the main text, Jamarillo et al. (2007) relied on old methane emission factors from the EPA from 1996, now updated and increased by the EPA (2011a). In their analysis, Fulton et al. (2011) found that using the EPA (2011a) factors increased the U.S. natural gas emissions in 2008 by 150%.

Howarth et al. (2011)

In Howarth et al. (2011), we gave a range of methane emission estimates for both shale gas and conventional gas,

expressed as a percentage of the lifetime production of a well. In Table 1, we converted these to mass of C of methane per LHV energy of the gas as explained in the Electronic Supplemental Materials of Howarth et al. (2011).

EPA (2011a)

The revised U.S. greenhouse gas inventory as of April 2011 reports methane emissions for 2009 from natural gas systems as 7.9 Tg C yr^{-1} (presented as 10,535 Gg CH_4 yr^{-1}, as mass of methane), with a 95% confidence-level range of 6.4 Tg C yr^{-1} to 10.3 Tg C yr^{-1} (EPA 2011a). Note that this estimate excludes emissions from associated well production, as EPA (2011a) assigns those emissions to petroleum systems rather than natural gas systems. Total natural gas production in the U.S. in 2009, excluding associated well production, was 566 x 109 m^3 yr^{-1} (20 trillion cf yr^{-1}; EIA 2011a). Normalizing emissions to this production yields a national emission intensity estimate of 0.40 g C MJ^{-1} of methane (LHV, and excluding associated well production). However, this averages shale gas and other unconventional gas with conventional gas productions and emissions. In 2009, shale gas contributed only 13% of production of natural gas in the U.S. (EIA 2011b). Furthermore, EPA's emission inventory does not account for shale gas activity in the Northeast region nor any U.S. tight sand activity (EPA 2011a) and pre-production emissions need to be normalized accordingly.

For Table 1, we separated estimates of emissions from unconventional gas and conventional gas from the EPA dataset (EPA 2011a, Annex 3) using the upstream estimated methane emissions specific to each category and normalized these emissions according to appropriate production data for 2009 from EIA (2011a).

- Completion and work-over emissions for unconventional wells: Methane emissions during completion and work-over of unconventional wells in 2009 in the U.S. are estimated as 983 Gg C yr^{-1} (EPA 2011a). This includes shale-gas wells in the Mid-continent, Rocky Mountain (work-overs only), and Southwest regions only. At the time the EPA (2011a) report was released, methane emission estimates for tight-sand gas and for the Marcellus shale play were not available for 2009. Coal-bed methane emissions (Rocky Mountain and Gulf Coast) are listed separately and total 69.2 Gg C yr^{-1} (EPA 2011a). Well emissions add an additional 3.8 Gg C yr^{-1}, for total pre-production methane emissions of 1.1 Tg C yr^{-1}. Total shale gas and CBM production from these regions for 2009 was 118 x 109 m^3 yr^{-1} (4.2 trillion cf yr^{-1}; EIA 2011a). Therefore, pre-production emissions normalized to unconventional production are 0.26 g C MJ^{-1} of methane (LHV). We include both shale gas and coal-bed methane wells in this calculation, since the development of shale gas is such a new phenomenon and is undergoing a rapid increase in growth; using just the shale-gas data may tend to overestimate completion emissions per level of production. On the other hand, our use of the combined shale gas and coal-bed methane estimate is probably conservative for shale gas, as completion emissions per production are higher for shale than for coal-bed methane gas (EPA 2010). Further, note that EPA (2011a) assumes that only 50% of methane flows during well completion are vented (EPA reports aggregated regulatory emission reductions for the entire production stream which include completion flaring; we apply all regulatory emission reductions to routine well-site emissions). A later report from EPA (2011b) states that more likely 85% of the methane is vented, and only 15% flared or captured for market. If so, the EPA (2011a) total upstream emission estimates in Table 1 of our main text are highly conservative. We note, though, that both the methane flux during flow-back and the percentage of that flux that is vented will vary widely from well to well, and remain statistically poorly known.

- Completion and work-over emissions for conventional wells: For conventional natural gas, EPA (2011a) reports methane emissions during well completion and work-overs of 0.8 Gg C yr^{-1} and well emissions of 46.5 Gg C yr^{-1}. Emissions from offshore platforms are an additional 226 Gg C yr^{-1}, for a total of 273 Gg C yr^{-1} of methane. Production for non-associated gas wells in 2009, including both on-shore and offshore, was 176 x 109 m^3 yr^{-1} (6.2 trillion cf yr^{-1}; EIA 2011a). We include both on-shore and off-shore wells, as a robust estimate for both is more easily obtained from the EPA (2011a) inventory. This yields an estimate of 0.05 g C MJ^{-1} of methane, or an order of magnitude less than for the emissions from unconventional wells during completion and work-overs.

- Routine well-site emissions: We subtracted the emissions estimate for completion and work-overs for conventional wells and unconventional wells (above) from the total upstream emissions in Annex 3 of EPA (2011a). We further subtracted reductions resulting from GasSTAR and regulatory measures. This yields a national estimate of 3.34 Tg C yr^{-1} methane. This estimate was then divided by total natural gas production (566 x 109 m^3 yr^{-1}; see above) resulting in an estimate of 0.17 g C MJ^{-1} for routine miscellaneous production emissions beyond those from well completions

and work-overs. We applied these routine production emissions to both conventional and unconventional wells. GAO (2010) reports routine production estimates from federal leases in unconventional plays ranging from 0.04 g C MJ^{-1} to 0.23 g C MJ^{-1}. Our estimate falls close to the median value from the GAO (2010) report (0.14 g C MJ^{-1}; assuming EPA default natural gas composition of 78.8% methane).

- Mid- and downstream emissions: Other life-cycle emissions are simply the total emissions reported for gas processing (EPA 2011a, table A-128), transmission and storage (EPA 2011a, table A-129), and distribution (EPA 2011a, table A-130) streams minus the reported GasSTAR and regulatory emission reductions for each stream, all converted to g C MJ^{-1} of methane (LHV). Processing emissions (0.03 g C MJ^{-1}) match those reported by Howarth et al (2011), while downstream (transmission/storage and distribution) emissions reported by EPA (0.13 g C MJ^{-1}) are lower than the Howarth et al (2011a) estimated range of 0.21 – 0.56 g C MJ^{-1}. However, EPA (2011a) notes that they expect to further revise emission factors for the transmission/storage stream. See discussion in main text.

Summing the upsteam, midstream and downstream emissions from the EPA (2011a) data, we calculate a total life-cycle methane emission of 0.38 g C MJ^{-1} of methane for conventional gas and 0.60 g C MJ^{-1} of methane for unconventional gas. As a check on these assumptions, note that 13% of total U.S. natural gas production from unconventional gas at 0.60 g C MJ^{-1} plus 87% of conventional gas at 0.38 g C MJ^{-1} agrees with the national aggregate value of emissions from all natural gas or 0.40 g C MJ^{-1} of methane.

Jiang et al. (2011)

In their Figure 3, Jiang et al. (2011) report 1.15 g CO_2-e MJ^{-1} of methane emission from pre-production shale-gas wells without gathering lines (online supplementary material, Table 1.6). They report their estimate for methane emissions for the production to distribution streams in their Figure 4. We summed these emissions, and converted to 0.30 g C MJ^{-1} of methane, using their assumed global warming potential of 25 and the LHV energy content for natural gas. Of this estimate, 0.21 g C MJ^{-1} are from well-site upstream emissions, and 0.05 g C MJ^{-1} are downstream emissions from transmission, storage, and distribution. These downstream emission estimates of Jiang et al. (2011) are only about one-third of those from EPA (2011a), and are lower than those from any other paper or report that has examined the greenhouse gas footprint of shale gas. The upstream emissions of Jiang et al. (2011) are half of the value estimated by EPA (2011a) for unconventional gas.

Fulton et al. (2011)

In their exhibit 6, Fulton et al. (2011) reports methane emissions from U.S. natural gas production for 2008 of 12 kg CO_2e $MMBtu^{-1}$. End-use combustion emissions indicate that they reported emissions in terms of HHV. We simply converted their value to the LHV convention and to mass of C per MJ from mass per BTU, using their assumed global warming potential estimate of 25. This yields 0.38 g C MJ^{-1} of methane. Note that this represents the total U.S. gas industry for 2008 (conventional and unconventional gas) and is based on emissions reported in EPA (2011). We report this value in Table 1 under the category of "conventional gas," with a footnote that it somewhat overestimates conventional gas since some unconventional gas is included. We believe this is a small difference, though. Note that for the EPA (2011a) estimates presented above, the emissions estimate just for conventional gas is 0.38 g C MJ^{-1}, while that for all natural gas systems in the U.S. in 2009 was 0.40 g C MJ^{-1}.

Hultman et al. (2011)

Hultman et al. (2011) report U.S. methane emissions from production to distribution streams for conventional and unconventional gas in their Table 2 and total life-cycle emission intensity (including carbon dioxide emissions) in their Table 4. We calculated the production-to-distribution emission intensity from emissions in Table 2 assuming 2007 non-associated natural gas production of 18.4 EJ (LHV, EIA 2011b). We then back-calculated pre-production, well-completion emission intensities from life-cycle emission factors given in Table 4, adjusting for heating value as discussed above and subtracting combustion CO_2 emissions (55.9 g CO_2 MJ^{-1}). Total lifecycle methane emissions are 0.35 g C MJ^{-1} (conventional) and 0.57 g C MJ^{-1} (unconventional). The estimates of Hultman et al. (2011) compare well with those from EPA (2011a), with 0.40 g C MJ^{-1} from upstream sources and 0.14 g C MJ^{-1} from downstream emissions. Note that Hultman et al. (2011) assume that 85% of the gas in flowback is vented, with only 15% flared or captured for sale.

Skone et al. (2011)

Skone et al. (2011) report emissions for several sectors of shale and conventional gas development in their Table B-1. Converting these from mass of methane to mass C in methane and from HHV to LHV yields emission estimates of 0.29 g C MJ^{-1} for shale gas extraction and processing and 0.19 g C MJ^{-1} for conventional gas extraction and processing. Skone et al (2011) estimate transmission and storage emissions of 0.08 g C MJ^{-1}. They apparently assume no distribution emissions. The total estimated emissions is 0.37 g C MJ^{-1} of methane for shale gas and 0.27 g C MJ^{-1} of methane for conventional gas. Total shale gas emissions in Skone et al. (2011a) are approximately 60% of the estimate from EPA (2011a) for total emissions, for upstream emissions, and for emissions during transmission and storage. Note that Hughes (2011a) evaluated an oral presentation by Skone that served as the basis for Skone et al. (2011), and concluded that emissions per unit of heat energy were probably under estimated due to over estimation of production from shale gas wells. See figure A below.

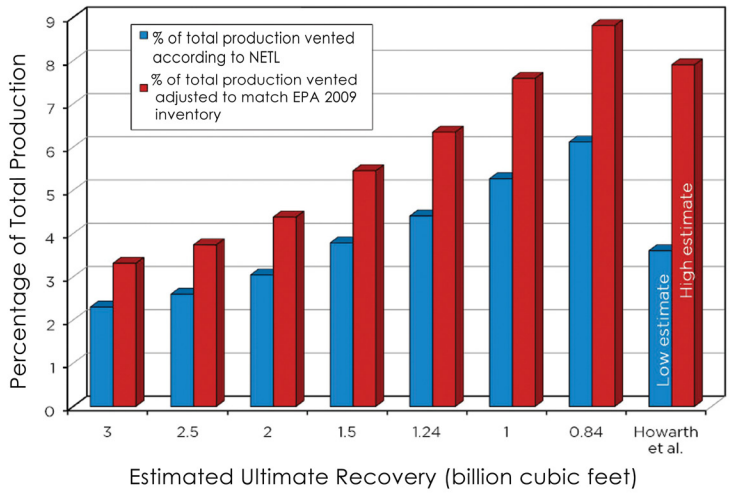

Figure A. Methane emissions from development of Barnett shale gas, expressed as a percentage of the life-time production of a well. Estimates from Howarth et al. (2011) are shown to the right, with our low estimate in blue and high estimate in red. Other estimates are based on the presentation by Skone, as analyzed by Hughes (2011a). The Skone estimates are shown as a function of the estimated ultimate recovery for an average well, with (red bars) and without (blue bars) adjustment to match the EPA (2011a) national greenhouse gas inventory. The unadjusted, blue bar corresponding to 3 billion cubic feet of estimated ultimate recovery is the estimate presented by Skone. Hughes (2011a) indicates that the red bars for 1 or 0.84 billion cubic feet would be better estimates. With these adjustments, emission estimates from Skone agree reasonably well with those from Howarth et al. (2011). Reprinted from Hughes (2011a).

Burnham et al (2011)

Methane emissions from conventional and natural gas streams in the newest GREET model (Argonne National Lab 2011) are based on Burnham et al. (2011), and we use the GREET calculations to arrive at emission intensities for both conventional and shale gas. Upstream emissions are estimated at 0.28 g C MJ^{-1} for conventional gas and 0.17 g C MJ^{-1} for shale gas. While Burnham et al. (2011) note that liquids unloading may be required in some shale gas wells, the emissions associated with the practice are attributed by them to conventional wells only. This assumption contrasts with that made by us (Howarth et al. 2011) that liquid unloading occurs in both conventional and shale gas well. The assumption by Burnham et al. (2011) that shale gas wells have no liquid unloading largely drives their conclusion that the emissions from shale gas wells are less than from conventional wells. Further, we believe Burnham et al. (2011) may have underestimated emissions for well completions and workovers; they appear to have used emission factors from EPA (2010) that are expressed as methane, but reduced these on the mistaken belief that those factors were for natural gas composed of methane and other gases.

Burnham et al. (2011), assume a 0.147% emission rate in processing, or 0.02 g C MJ^{-1} assuming GREET LHV and gas density. Methane losses in the transportation/storage/distribution sector are estimated to be 0.09 g C MJ^{-1}.

Cathles et al. (2012)

Cathles et al. (2012) suggest a range of methane emission estimates for both shale gas and conventional gas, expressed as a percentage of the lifetime production of a well. We converted these to mass of C of methane per LHV energy of the gas as explained in the Electronic Supplemental Materials of Howarth et al. (2011).

Calculations and Information in Support of Figure 3

Until 2011, EPA used emission factors from 1996 for the national greenhouse gas (GHG) inventory, but, as of April 2011, they began to use revised emission factors presented in EPA (2010). This resulted in a factor of two increase in the estimated methane emissions from natural gas systems in the U.S., making natural gas the largest source of methane pollution in the country. But even the April 2011 estimates were too low. EPA (2011a) estimated methane emissions from natural gas systems in 2009 as just over 220 Tg yr^{-1}, expressed as mass of CO_2-equivalents. EPA (2011b) subsequently increased this by 80 Tg CO_2-equivalents yr^{-1}, as they obtained better data on methane from shale and tight-sand gas in 2009, for a total of approximately 300 Tg CO_2-equivalents yr^{-1}. With this latest addition, natural gas systems comprise almost 40% of all anthropogenic methane emissions from the U.S.

For the national GHG inventory, EPA (2011a, 2011b) relied on a global warming potential (GWP) value of 21 for methane, reflecting the century time scale and using the GWP value from the IPCC (1995) assessment. More recently, IPCC (2007) provided updated information on GWP values, presenting a value of 25 for the century time scale and 72 for the 20-year time scale. More recently yet, Shindell et al. (2009) gave mean GWP values of 33 for the century time scale and 105 for the integrated 20-year time frame after methane emission, based on a model that more fully accounts for the interaction of methane with other radiatively active substances in the atmosphere. In Figure 3 of our main text, we use these most recent estimates from Shindell et al. (2009) to show the contribution of methane to the entire GHG inventory of the U.S. at both the 20-year and 100-year time scales.

Electricity vs. Other Uses of Natural Gas

Currently, only about 30% of natural gas in the U.S. is used for electricity generation, and most is used for heating needs in industrial, commercial, and domestic markets (Fig. B). How will shale gas be used in the future? The best evidence for the U.S. is that shale gas largely will be used to replace conventional gas uses, as conventional gas becomes depleted (EIA 2011a; Hughes 2011b). As indicated in Figure C, the U.S. Department of Energy predicts a large growth in shale gas over coming decades, but little growth in total supply of natural gas. The shale gas is predicted to largely replace conventional gas resources, as those become more depleted, and to some extent replace imported gas from Canada. Without strong and enforcement to reduce emissions, the consequences for GHG emission of continuing to switch from conventional gas to shale gas would be to increase the life-cycle emissions for using natural gas by approximately 40 to 60%, as we discuss in our accompanying paper. The natural gas industry is already the single largest source of methane emissions in the U.S. (EPA 2011b), and a very important portion of the U.S. national GHG inventory, as shown in Figure 3 of the accompanying paper.

Most recent reports on the shale-gas GHG footprint have focused on electricity production (Jiang et al. 2011; Fulton et al. 2011; Wigley 2011; Hultman et al. 2011; Skone et al. 2011). This is appropriate, if the question is: how might displacement of electricity production from coal by shale gas affect GHG emissions? Electricity production may well be the best use of natural gas, including shale gas. But is this substitution of shale gas for coal to generate electricity likely to be the largest use of shale gas? We are highly skeptical, without a strong energy policy that greatly reduces other uses of natural gas. We urge that more studies broaden their focus beyond electricity generation.

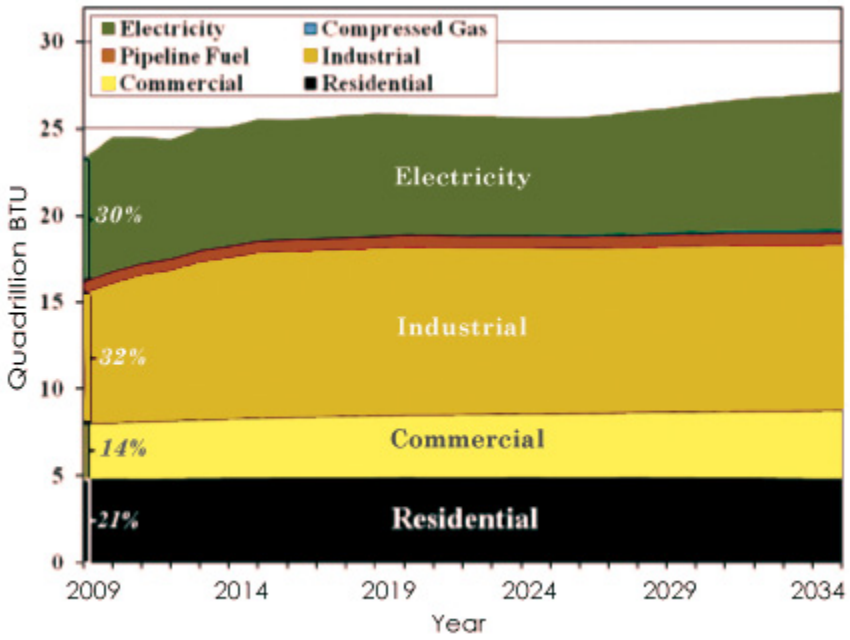

Figure B. Projections from the Energy Information Administration of the Department of Energy for future use of natural gas in the U.S. No major changes in the distribution of use are predicted, with only modest overall growth in natural gas consumption. Note that production of electricity made up only 30% of gas consumption in 2009, and is predicted to remain near this percentage. Most natural gas is used for residential and commercial heating and industrial processes. Reprinted from EIA (2011c).

Within the consideration of the use of shale gas for electricity generation, a variety of assumptions are possible concerning the efficiency of generation from natural gas and coal. One can compare the efficiencies of currently operating coal and natural gas electric plants, or the greatest efficiencies available in new gas and coal plants. Clearly, new natural-gas fired electric plants using cogeneration are far more efficient than half-century old coal-fired plants. Cogeneration is also possible with coal plants, though. We believe most of the recent studies have fairly compared the efficiencies of coal and natural gas electric plants, and note the efficiencies in most studies are comparable to those we used in Howarth et al. (2011). However, the 90% efficiency for combined heat and electricity production (CHP) using natural gas stated by Cathles et al. – without any support by referencing – is much higher than other studies. While such efficiencies may be possible, they should correctly be compared to efficiencies of 70% to 80% that are currently observed in some new coal-fired CHP plants in Denmark (D. Hughes, pers. comm.).

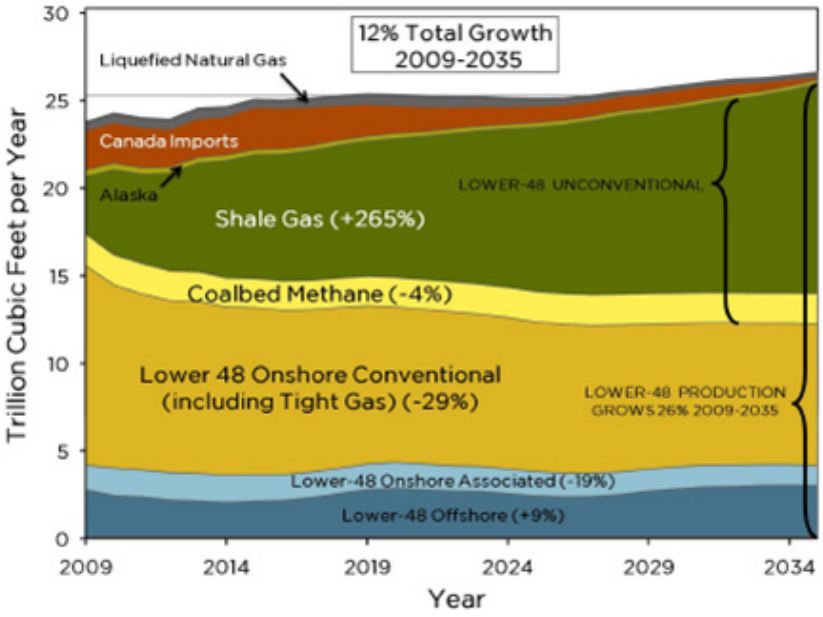

Figure C. Projected sources of natural gas for the U.S. from 2009 through 2034, based on estimates from the Energy Information Administration of the U.S. Department of Energy, as redrawn by Hughes (2011a). Overall growth in availability of natural gas is predicted to be small, with shale gas expected to replace decreasing production from conventional gas and tight-gas formations, as well as to displace some modest imports from Canada. As discussed in the text, the predicted increase in shale gas production seems optimistic. Reprinted from Hughes (2011b).

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