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The greenhouse impact of unconventional gas for electricity generation

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Abstract
New techniques to extract natural gas from unconventional resources have become economically competitive over the past several years, leading to a rapid and largely unanticipated expansion in natural gas production. The US Energy Information Administration projects that unconventional gas will supply nearly half of US gas production by 2035. In addition, by significantly expanding and diversifying the gas supply internationally, the exploitation of new unconventional gas resources has the potential to reshape energy policy at national and international levels—altering geopolitics and energy security, recasting the economics of energy technology investment decisions, and shifting trends in greenhouse gas (GHG) emissions. In anticipation of this expansion, one of the perceived core advantages of unconventional gas—its relatively moderate GHG impact compared to coal—has recently come under scrutiny. In this paper, we compare the GHG footprints of conventional natural gas, unconventional natural gas (i.e. shale gas that has been produced using the process of hydraulic fracturing, or 'fracking'), and coal in a transparent and consistent way, focusing primarily on the electricity generation sector. We show that for electricity generation the GHG impacts of shale gas are 11% higher than those of conventional gas, and only 56% that of coal for standard assumptions.

Keywords: unconventional gas, fracking, hydraulic fracturing, greenhouse gases, shale gas, energy policy

1. Introduction

New techniques to extract natural gas from unconventional resources—such as shales or tight sands—have become economically competitive over the past several years, leading to a rapid and unanticipated expansion in natural gas production. These techniques led to an increase in US production of unconventional gas at an average annual rate of 17% between 2000 and 2006. Production further increased by 45% from 2006 to 2010 (Energy Information Administration 2011a). The US Energy Information Administration (EIA) projects that unconventional gas will supply nearly half of US gas production by 2035, up from 16% in 2009 (figure 1). In addition, unconventional gas reserves are found in many places worldwide and exploration continues. This widespread geographic distribution, combined with new production techniques, implies a substantial potential for global deployment of unconventional gas extraction (Energy Information Administration 2011c).

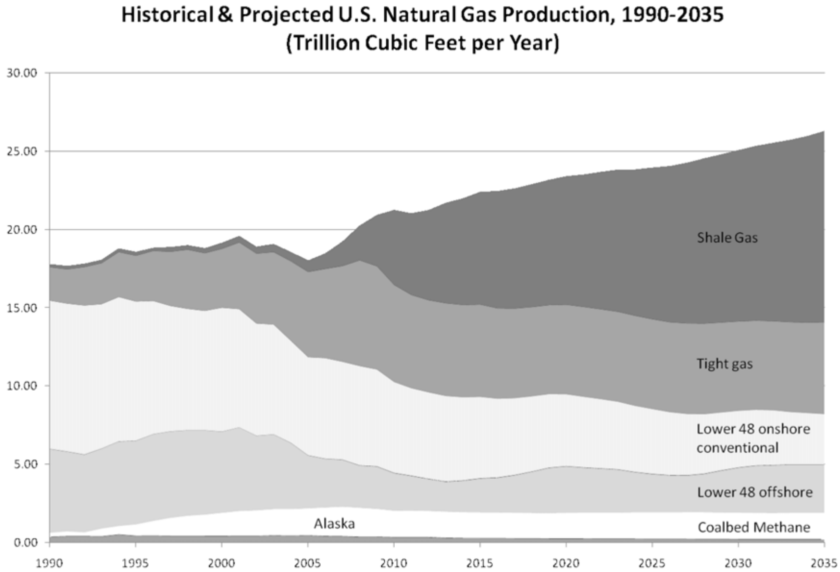

Figure 1. US natural gas production 1990–2035, showing recent and projected increases in unconventional (shale and tight) gas production. Data from EIA (Energy Information Administration 2011a).

By significantly expanding and diversifying the gas supply, the exploitation of new unconventional gas resources has the potential to reshape energy policy at national and international levels—altering geopolitics and energy security, recasting the economics of energy technology investment decisions, and shifting trends in greenhouse gas (GHG) emissions. Absent a carbon price, electricity generation from gas could constitute a highly competitive option relative to nuclear, many renewables, and even coal. Nevertheless, in the wake of the recent rapid expansion of this technology, and in anticipation of continued rapid growth, reasonable questions have been raised about the environmental and health impacts of shale gas extraction, particularly the possibility of contamination of water from proprietary chemicals used in the fracturing process. In addition, more recently, one of the perceived core advantages of unconventional gas—its relatively moderate GHG impact compared to coal—has come under scrutiny. One recent and visible study has estimated that, per gigajoule of fuel, unconventional gas has a higher greenhouse gas footprint than coal (Howarth *et al* 2011). A forthcoming study by the National Energy Technology Laboratory (Skone 2011) sets out a comprehensive life-cycle-assessment (LCA) framework and finds a relatively minor GHG difference between conventional and unconventional gas. In this paper, we compare the GHG footprints of conventional natural gas, unconventional natural gas (i.e. shale gas that has been produced using the process of hydraulic fracturing, or 'fracking'), and coal in a transparent and consistent way, focusing primarily on the electricity generation sector. We show that for electricity generation the GHG impacts of shale gas are only marginally higher than those of conventional gas, and both remain substantially lower than those of coal under standard assumptions.

2. The greenhouse footprint of conventional and unconventional gas

Gas produced from unconventional wells has roughly the same methane content as that produced from conventional wells (Rojey 1997)[5] and therefore combustion can be assumed to yield the same climate effect. However, extraction techniques for unconventional gas differ from those used for conventional gas, and figures on well-lifecycle methane emissions have not been comprehensively established. Unlike other unconventional fossil fuel production, such as the extraction of petroleum from oil sands, these new gas extraction methods do not require substantial amounts of energy to process the resource. They rely instead on a technique called hydraulic fracturing that injects a fluid under high pressure into the geological formation, creating fractures in the rock. The fluid is then withdrawn, a well is established, and the gas embedded in the rock diffuses to the surface. While the data are still uncertain, the fracturing process may release substantial amounts of methane directly into the atmosphere (called fugitive methane emissions). Methane is a potent GHG, so the emissions from this process could substantially increase the greenhouse footprint of unconventional gas compared to conventional gas.

Calculating the GHG footprint of unconventional gas requires three steps and associated assumptions. First, emissions of GHG from the production process, leaked methane and CO_2, must be estimated. Second, these numbers

[5] Typically, the composition of associated gas (that generated in tandem with crude oil) is distinct from non-associated gas, but even that generalization is blurry. The line between conventional and unconventional gas cuts across the division between associated and non-associated gas; therefore there is no easy way to establish a correlation between the conventionality of gas production and its methane content. For the purposes of this paper, we assume the mean methane content of conventional and unconventional gas is equivalent.

must be converted to a common GHG metric such as CO_2-equivalent (CO_2e). Third, because electricity generation technologies vary greatly in their combustion efficiencies, the emissions attributable to a kilogram or GJ of fuel are more appropriately compared on the basis of electricity delivered to the end-user—i.e. on a per kWh basis. In this section, we explain our approach to each of these steps and present results comparing the greenhouse footprint of electricity generated from conventional natural gas, unconventional natural gas, and coal.

2.1. Fugitive emissions from natural gas production

Despite the use of either flaring or control and capture technologies, natural gas routinely leaks or is vented during well drilling and operation. These fugitive emissions contain a heavy concentration of methane, which, because of its high radiative forcing, can contribute significantly to the global warming impact of natural gas mining operations. We consider fugitive emissions from nine distinct segments of the production process: well drilling and completion, periodic well workovers, routine production activities, processing, transmission, storage, liquefied natural gas (LNG) storage, LNG processing terminals, and distribution[6]. Calculations are based on an aggregated data set provided by the United States Environmental Protection Agency (US Environmental Protection Agency 2010). Each statistic is presented for both conventional and unconventional natural gas wells, with the latter comprised of shale and tight sands formations, and coal bed methane[7]. Calculations are presented on a per well basis and multiplied by the total number of unconventional wells (including tight sands) to yield an aggregate value. The omission of tight sands data does not skew these results[8]. Estimating total production from an 'average' well is not straightforward. Natural gas wells exhibit considerable variability in production lifetime, and the mean half-life of US domestic wells has shifted over time. EIA data indicate that the half-life of wells that first produced in 1990 was roughly 40 months, whereas that for wells that first produced in 1999 was 25 months (Energy Information Administration 2001). A well half-life of 30 months is used here as a reasonable estimate of productivity, and we assume that gas wells will remain active until 85%–95% of the original reserves have been depleted (Energy Information Administration 2001). After ten years, roughly 95% of the natural gas reserves will have been depleted[9]. We use this as our mean well lifetime; one-time emission events like well completion are spread over that lifetime to calculate average annual emissions. The coal fugitive emissions were taken directly from EIA data (Energy Information Administration 2009c)[10] on emissions of greenhouse gases DOE/EIA-0573. Conventional gas data were taken from the same report cited in calculating fugitive emissions from unconventional sources. The original datasets were comparable, but the publicly available coal data were more limited than those for gas. There is no *a priori* reason to suspect the coal data are less accurate.

2.1.1. Flowback from well completion and workover. Fugitive emissions escape in two ways: first, during well completion activities as fracturing fluids are expelled in a process called flowback; and second, as geological leaks occur before equipment is installed and sealed. Additionally, during the production lifetime, wells often require major overhauls called workovers, yielding additional emissions. The EPA data estimate emissions factors for natural gas wells assuming 'high rate, extended flowback to expel fracture fluids and sand proppant', which leads to higher natural gas emissions. Estimates of 36.65 Mcf/completion and 2.454 Mcf/workover are used for conventional natural gas wells. For unconventional natural gas wells, 9175 Mcf/completion and 9175 Mcf/workover are used (US Environmental Protection Agency 2010).

It is worth noting that this difference in flowback emissions will account for most of the GHG difference between conventional and unconventional gas. At the time of writing, the publicly available estimates for flowback emissions from unconventional gas were based on preliminary EPA figures and are therefore highly uncertain (see annexe 3 in US Environmental Protection Agency (2011a) and MIT appendix 1A in Moniz *et al* (2011)). The numbers are derived from non-peer-reviewed presentations at EPA workshops that do not document their sources. It is moreover possible that, since the workshops that designed to identify sources of potential GHG reduction, there might have been incentives to present inflated numbers. Even if there is no inherent bias, the numbers are likely to be revised as further information becomes available. It is possible that the numbers are off by a factor of two, or even ten. Unfortunately, just as the data are uncertain, so too are the uncertainties. As such, we have decided not to make an estimate of how far off these numbers are. We will return to this point in the discussion of our results.

While assuming the same emissions factor for flowback as for completion may overestimate the former, it is used here as a conservative figure. Workovers take place about once per decade. Assuming the above lifetime of 10 years, this results in an average of one completion event and one workover event per well. Calculations for the CO_2 equivalent emissions from completion and workover activities for conventional and unconventional natural gas wells are shown in table 1.

To estimate the fraction of leaked gas that is flared during well operations, we use the conservative estimate of 15% combustion and 85% direct venting. This is

[6] Emissions for LNG are small with respect to the other terms.

[7] While the source data do not consider tight sand formations, it is assumed that all unconventional gas sources have a similar emissions profile.

[8] This claim is made based on the assumption that fugitive emissions from tight sands formations are comparable to those from other unconventional sources. We did not have explicit emissions data from tight sands, but we know the number of tight sands wells that exist. By using emissions data from the other unconventional sources, we can calculate the annual emissions per well (which applies to all unconventional sources including tight sands, per our assumption that they have similar emissions profiles). We then multiply that number by the total number of unconventional wells to get an approximation of all fugitive emissions from unconventional sources.

[9] Ten years represents about four half-lives for the depletion of a well.

[10] Table 17 (www.eia.gov/oiaf/1605/ggrpt/methane.html) specifies US methane emissions from energy sources and gives numbers for surface and underground coal mining.

Table 1. Fugitive methane emissions from well completion and workover for both conventional and unconventional gas production. Source: US Environmental Protection Agency (2010).

		Conventional gas		Unconventional gas	
		Completion	Workover	Completion	Workover
Aspect of production process		per well			
Emissions factor	$m^3\ y^{-1}$	1037.8	69.5	259 807	259 807
Natural gas vented	$m^3\ y^{-1}$	882.1	59.1	220 836	220 836
Methane vented	$m^3\ y^{-1}$	695.1	46.5	174 018	174 018
Natural gas flared	$m^3\ y^{-1}$	152.6	10.2	38 192	38 192
Methane flared	$m^3\ y^{-1}$	120.2	8.0	30 095	30 095
Methane flared	$kg\ y^{-1}$	81.8	5.5	20 488	20 488
CO_2 from flaring	$kg\ y^{-1}$	224.5	15.0	56 208	56 208
CH_4 vented form flaring pipes	$m^3\ y^{-1}$	3.1	0.2	779	779
Total methane vented	$m^3\ y^{-1}$	698.2	46.8	174 798	174 798
Total methane vented	kg	475.4	31.8	119 000	119 000
Total methane vented, annualized	$kg\ y^{-1}$	47.5	3.2	11 900	11 900
CO_2e from vented methane	$t\ y^{-1}$	11.9	0.8	2974 998	2974 998
Total CO_2e	t	12.1	0.8	3031	3031
CO_2e, annualized	$t\ y^{-1}$	1.2	0.1	303	303
CO_2 from flaring	$t\ y^{-1}$	22.5	1.5	5621	5621

Table 2. Fugitive emissions from production, aggregated for the United States (US Environmental Protection Agency 2010).

Segment	Methane emissions (kg)
Onshore production	2.376×10^9
Processing	6.984×10^8
Transmission	1.869×10^9
Storage	3.456×10^8
LNG storage	7.383×10^7
LNG terminals	1.455×10^7
Distribution	1.300×10^9
Total	6.678×10^9

consistent with the EPA's estimate for flaring assuming all unconventional wells (including tight sands) are accounted for (US Environmental Protection Agency 2010). We assume a natural gas composition of 78.8% CH_4. The global warming impact contribution from other constituent gases is considered to be negligible (US Environmental Protection Agency 2010). Of the flared gas, 98% undergoes perfect stoichiometric combustion (US Environmental Protection Agency 2010). Given the atomic weights of 1.008, 12.01, and 16.00 for H, C, and O respectively, every pound of CH_4 that is combusted yields 2.743 pounds of CO_2. We use a density of 0.0425 lb/ft^3 for methane (Air Liquide 2011). Results show that completion and workover events for conventional natural gas wells release 475 and 32 kg of methane respectively. Completion and workover events for unconventional gas wells release 119 000 kg of methane each.

2.1.2. Emissions from other aspects of production. Data from the EPA on other aspects of natural gas systems include aggregated national annual totals (table 2). Production, which includes fugitive emissions from equipment leaks as well as venting and flaring activities, emits $2.376 \cdot 10^9$ kg of methane. This is shown in table 2, along with other major segments of the gas cycle.

We total the emissions for 431 035 gas wells, both conventional and unconventional. We assume that, after drilling and with the exception of workover, both well types contribute equally to emissions in the natural gas system. The natural gas industry emits $6.678 \cdot 10^9$ kg of methane each year through these processes.

EPA estimates show that in 2007 liquid unloading from conventional wells released 223 billion cubic feet (Bcf) of natural gas. While only 41.5% of conventional wells require unloading, this number can be distributed over the entire population of conventional wells to illustrate the sector average. Following industry convention, we assume that unconventional wells do not require unloading: conventional wells are hampered by liquid loading, in which the build up of fluids eventually plugs wells and prevents gas from flowing freely. Unconventional wells are not hindered by the same effect, and do not require regular unloading. The annual total, considering 389 245 conventional wells, is $3.388 \cdot 10^9$ kg of methane.

2.2. Selection of global warming potentials

Estimates of the conventional and unconventional gas GHG footprint are sensitive to the scaling factor used to convert emissions of methane from well completion into equivalent emissions of CO_2. Methane is a 'high-leverage' GHG; 1 kg of methane produces a radiative forcing that is many times that from a kilogram of CO_2. Normally, the conversion to CO_2e is performed using an accepted if imperfect indicator called the global warming potential (GWP). GWP accounts for several factors, including the strength of radiative forcing in the atmosphere as well as the expected decay of the gas in the atmosphere. Because of these multiple components (magnitude and time), GWP is conventionally calculated on one of three timescales—a 20 y, 100 y, or 500 y scale, where the baseline for each is that the GWP for CO_2 is defined as exactly 1. Methane has the ability to trap large amounts of infrared radiation relative to CO_2, but it also has a comparatively shorter lifetime in the atmosphere. As a result, methane's 100 y GWP is much lower than its 20 y GWP. The IPCC estimates the GWP of methane to be 72 times that of CO_2 over a 20 y time horizon and 25 times CO_2 over a 100 y horizon (Solomon *et al* 2007). By comparison, Howarth *et al* cite figures of 105 and 33 over the 20- and 100 y time horizons respectively, based largely on a recent assessment by Shindell *et al* (2009). Shindell *et al* argue that the standard numbers, as reported in the Fourth Assessment Report of the Intergovernmental Panel on Climate Change (AR4), do not adequately account for the interaction of methane with both direct and indirect aerosols (Shindell *et al* 2009). Modeling results from the Goddard Institute for Space Studies (GISS) Model for Physical Understanding of Composition-Climate Interactions and Impacts (G-PUCCINI) indicate that the GWP of methane may be significantly higher when its impact on aerosols is included (Shindell *et al* 2009). However, the GISS research group that wrote the Shindell *et al* paper published a follow-up study in 2010. In this letter, they estimated the radiative forcing of methane to be 0.41 W m^{-2}, not significantly different from the IPCC AR4 figure of $0.48(+/-0.05)$ W m^{-2} (Unger *et al* 2010). Significantly, the confidence interval for Shindell *et al*'s estimate of the 100 y GWP of methane ranges from 25 to 42, with 33 as the median best estimate. Howarth *et al* report only the median from this interval, without considering the error band around it. Selection of a GWP time horizon is a major factor in this calculation. While it is true that 20 y effects are important for the climate, it is also conventional to use a 100 y time horizon when comparing different greenhouse gas policies. Howarth *et al* emphasize the GWP of methane emissions over the 20 y time horizon, and also use a relatively high 20 y GWP, which greatly amplifies the apparent greenhouse footprint (Howarth *et al* 2011). Methane has an atmospheric lifetime of approximately 12 y, so its impacts are concentrated within the first 20 y (Solomon *et al* 2007). However, CO_2 has a considerably longer lifetime and its effects are therefore distributed over a much longer period. In considering the central question, which is how to trade off different fuels or energy options in a portfolio, there is no obviously correct choice of time horizon, and there are certainly robust arguments to support reducing long-lived gases preferentially since the momentum of radiative forcing will be substantially higher several decades in the future. Given reasonable alternative perspectives, it is appropriate to evaluate emissions using 20, 100, and 500 y GWPs, the values of which we present in table 3. Using these values allows us to combine the carbon embodied in the fuel (kg CO_2 per GJ fuel) described earlier with the GWP-weighted fugitive emissions described in section 2.1 to arrive at a total GHG equivalent per GJ fuel (table 4).

Table 3. Global warming potential ranges for methane for 20, 100, and 500 y time horizons. The low and middle case values are those currently accepted by IPCC in AR4 (Solomon *et al* 2007). The high 20 and 100 y values are those based on Shindell *et al* as quoted in Howarth *et al* (see text for discussion).

GWP methane	Low	Mid	High
20 y	72.0	72.0	105.0
100 y	25.0	25.0	42.0
500 y	7.6	7.6	7.6

Table 4. Total emissions factor for conventional gas, unconventional gas, and coal (kg CO_2 equivalent per GJ fuel). Figures are equal to the carbon content of fuel per unit of energy plus the GWP-weighted fugitive emissions as described earlier.

	Total emissions factor for fuel (kg CO_2e/GJ fuel)								
	Gas-conventional			Gas-unconventional			Coal		
	Low	Best	High	Low	Best	High	Low	Best	High
20 y	80.4	80.4	94.2	99.3	99.3	121.7	89.2	89.2	89.2
100 y	60.7	60.7	67.8	67.4	67.4	78.9	89.2	89.2	89.2
500 y	53.4	53.4	53.4	55.6	55.6	55.6	89.2	89.2	89.2

2.3. Emissions from electricity generation

Any comparison of the GHG emissions of fuel alternatives must consider the pathway by which each fuel creates useful energy services for the user. In this paper, we consider emissions from electricity generation, and so we present results not only for GHG emissions per GJ fuel but also for emissions per kWh of electricity generated. The per GJ emissions are useful primarily for comparing direct combustion for heat, such as for home heating or in cogeneration plants—two applications that are confined almost exclusively to gas, and therefore confound easy comparison with coal. In the US, by nameplate capacity, 11% of gas plants and 3% of coal plants feature cogeneration (US Environmental Protection Agency 2006). Our concern in this paper is primarily a direct comparison of emissions from the three fuels for electricity generation. However, we note that, in the US, substantial amounts of gas are used for other applications. Only 30% of gas is used for electricity production and the rest primarily for heating applications. In contrast, roughly 90% of coal energy is used for generation (Energy Information Administration 2011b, 2009b).

The remainder of the paper focuses on emissions from electricity production. Two factors lead to an overall carbon intensity advantage for gas during the combustion stage. First, gas releases more energy per unit of carbon emitted. Second, the technology used for combustion of gas is more thermodynamically efficient than that used for coal, enabling a larger amount of chemical potential energy in the fuel to be converted to electricity. Calculating the greenhouse footprint therefore requires estimates of both factors (Bellman *et al* 2007). In the absence of an assessment of fugitive emissions, a basic energy balance calculation shows that coal embodies about 75% more CO_2 per GJ than gas; if the difference in generation efficiency is included, coal produces about 100% more CO_2 per kWh of electricity generated.

We estimated the carbon intensity of these fuels using reported US CO_2 emissions weighted by reported MWh generated (US Environmental Protection Agency 2006). This resulted in estimates for average US carbon intensity of energy of approximately 50 kg CO_2 GJ^{-1} for gas and 89 kg CO_2 GJ^{-1}

for coal. These results are similar to other published values (Quick 2010, Hong and Slatick 1994).

Generation efficiency for this purpose can be estimated in several ways. The most straightforward approach to comparing US gas and US coal efficiency is simply to take the average fleet efficiencies for each fuel, which are readily calculable from EIA data. Such an estimate implies the premise that any new supply of coal or gas would be distributed to generation assets in roughly the same proportion they are today—a reasonable assumption since national markets with moderately efficient transportation exist for both fuels (rail for coal and pipelines for gas). Using this assumption, overall US coal and gas efficiencies are 33% and 38%, respectively. However, this premise of uniform fuel deployment may not hold if the marginal supply of fuel goes to certain generation assets preferentially—perhaps geographically or perhaps favoring one type of technology. It also may not hold if generation assets are operating near an upper limit for capacity factor.

This latter question has significant implications for the overall GHG calculation. In the US, the average fleet gas generation efficiency is still fairly low compared to the best new technologies that are being installed. This is in part because the overall fleet is a combination of older plants, some of which are simple boiler-type designs ($\eta \sim 30\%$) or simple turbines ($\eta \sim 33\%$), and newer combined cycle turbines ($\eta \sim 45\%$). In addition, much of the US gas capacity, including newer and older plants, is currently idle. In 2008, the US coal capacity factor was over 70% while the factor for conventional gas turbines was less than 30%, and the more advanced combined cycle gas turbines (CCGT) were running at approximately a 35% capacity factor. This implies substantial high-efficiency generation capacity that can be easily brought online with new gas supplies. Moreover, for longer-term energy policy and planning, the central question is not what current efficiencies are but what efficiencies are expected to be in 10 or 20 y. It is likely that the addition of new gas capacity will significantly increase the average fleet efficiency. New coal capacity is unlikely to increase average fleet efficiency to the same degree. For example, today's best coal technology is in the range of 40% (for IGCC and supercritical coal) whereas the best gas technology is in the range of 55% for CCGT (Energy Information Administration 2011d); at the upper end, the GE H-System combined cycle turbine runs at 58.4% efficiency (Bellman *et al* 2007). This imbalance in generation efficiency for individual generators is projected to increase fleet efficiency via new capital additions and replacement of old assets. The average efficiency of coal electricity generation is projected to increase to roughly 34% by 2030. Natural gas is projected to reach 40.1% efficiency by 2023 (Bellman *et al* 2007).

Table 5 shows generation efficiencies used in the calculations presented in this paper. We calculated the current fleet average emissions in both CO_2 kWh^{-1} and kg CO_2 GJ^{-1} from data reported in the EPA's CEMS 2009 GDM Report. These numbers are in close agreement with EIA estimates.

In order to ensure the national average was representative of power plants closest to shale gas production, we also calculated the regional emissions distribution for gas (Energy Information Administration 2011d). Regional emissions intensities varied by less than 4% for all regions with greater than 1% of national emissions from each fuel.

Table 5. Efficiency for coal and gas-fired electricity generation assets in the United States used for calculation of greenhouse gas emissions. See text for sources and discussion.

Current generation efficiencies in US	
Coal	
US average	33.95%
Median of most efficient 20	36.30%
Gas	
US average	38.94%
Average for current CCGT	45.90%
Average for Conv GT	33.70%
Future (2030) generation efficiency scenarios	
Coal	
High	38.93%
Mid	37.80%
Low	36.30%
Gas	
High	50.53%
Mid	47.41%
Low	43.08%

2.4. Calculating total GHG equivalent emissions

The per kWh total greenhouse footprint for each fuel was calculated as the sum of the GWP-weighted fugitive emissions (CH_4 and CO_2) and the CO_2 emitted from combustion. Fugitive emissions of methane and CO_2 from unconventional and conventional gas were estimated as described in section 2.1. Methane production from coal was calculated using national emissions information reported by the 2008 EIA report on GHG emissions in the US (US Environmental Protection Agency 2010). GWP selection and weighting was described in section 2.2. The resulting per GJ GHG figures for each fuel (conventional gas—CG, unconventional gas—UG, coal) were assumed to feed into generation assets with efficiencies that varied as described in section 2.3 (Energy Information Administration 2009a). Table 6 shows the results across different assumptions for GWP and technology. Across almost all assumptions, unconventional gas results in lower greenhouse gas emissions from electricity than does coal (figure 2). One must assume relatively inefficient gas combustion technology and a high-end 20 y GWP to realize gas emissions in excess of coal, which is similar to what Howarth *et al* found. In most cases, even under relatively high assumptions about fugitive emissions, the greenhouse footprint of unconventional gas is substantially below that of coal, and relatively close to conventional gas, for most other assumptions about technology and GWP. This result is presented in figure 3, which expresses the greenhouse footprint of CG and UG as a percentage of the emissions from coal, under these varying assumptions.

3. Mitigation and learning

Even if one assumes that fugitive methane emissions from well drilling and production are very high, it may be possible

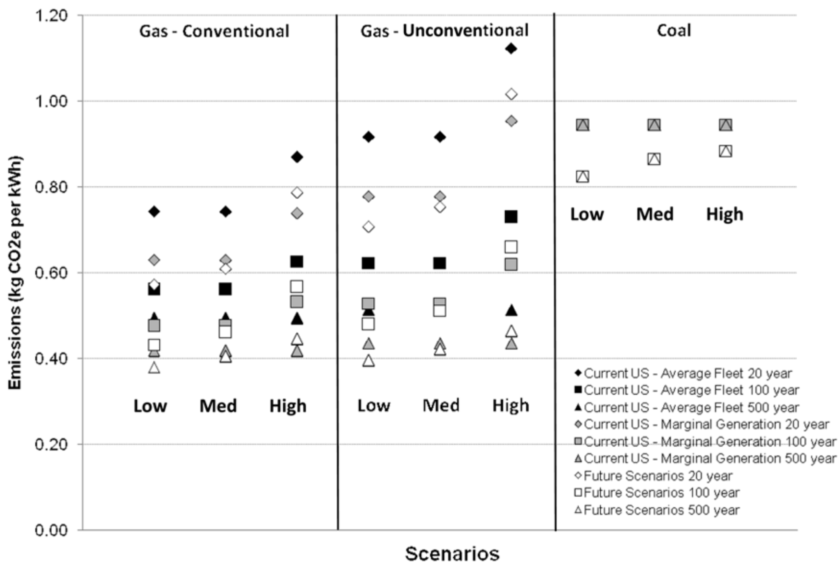

Figure 2. Comparison of combustion emissions intensity (kg CO_2 equivalent per kWh electricity generated) ranges under different technology and GWP assumptions.

Table 6. Combustion emissions intensity (kg CO_2 equivalent per kWh electric generated) for conventional gas, unconventional gas, and coal in the United States. 'Current US—average fleet' assumes new gas goes to generation with average fleet efficiency; 'Current US—marginal generation' assumes new gas goes to efficient existing generation capacity (CCGT); 'future scenarios' assumes alternative efficient technologies as described in the text.

	Combustion emissions intensity (kg $C0_2e$ kWh^{-1})								
	Gas-conventional			Gas-unconventional			Coal		
	Low	Best	High	Low	Best	High	Low	Best	High
Current US—average fleet									
20 y	0.743	0.743	0.871	0.918	0.918	1.125	0.946	0.946	0.946
100 y	0.561	0.561	0.627	0.623	0.623	0.730	0.945	0.945	0.945
500 y	0.494	0.494	0.494	0.514	0.514	0.514	0.945	0.945	0.945
Current US—marginal generation									
20 y	0.631	0.631	0.739	0.779	0.779	0.954	0.946	0.946	0.946
100 y	0.476	0.476	0.532	0.529	0.529	0.619	0.945	0.945	0.945
500 y	0.419	0.419	0.419	0.436	0.436	0.436	0.945	0.945	0.945
Future scenarios									
20 y	0.573	0.610	0.787	0.707	0.754	1.017	0.825	0.866	0.885
100 y	0.433	0.461	0.567	0.480	0.512	0.660	0.825	0.866	0.884
500 y	0.381	0.406	0.447	0.396	0.422	0.465	0.825	0.866	0.884

to reduce these emissions significantly by using better leak mitigation technologies and practices. The Environmental Protection Agency's Natural Gas STAR (NG STAR) Program lists over 30 recommended technologies and practices that natural gas producers can use to reduce their emissions during the well production stage alone (US Environmental Protection Agency 2011b). For example, one NG STAR industry partner reduced their fugitive emissions by more than 72 000 Mcf y^{-1} by redesigning their blowdown systems and altering their emergency shutdown systems (Natural Gas Star 2004). Like many of NG STAR's other recommended technologies and practices, these measures are extremely cost effective. Based on reports from industry, NG STAR estimates that changing these systems has a capital cost of less than $1000 and a payback period of less than one year (Natural Gas Star 2004). This makes it extremely likely that unconventional gas drillers would adopt these practices over time (Seto 2011).

However, without knowing the magnitude and exact sources of fugitive emissions from unconventional natural gas, it is difficult to state with authority what effects better mitigation technology and practices might have, or whether these practices will further the advantage of unconventional gas over coal in lifecycle GHG emissions. We were unable to find good data on fugitive emissions from unconventional gas production in general, much less data documenting the equipment and practices most commonly used by these wells. This is at least partially because NG STAR and EPA do not currently track fugitive emissions from unconventional wells separately from overall figures.

4. Discussion

There can remain little doubt that, by increasing the availability of low-cost natural gas across many geographical regions, the

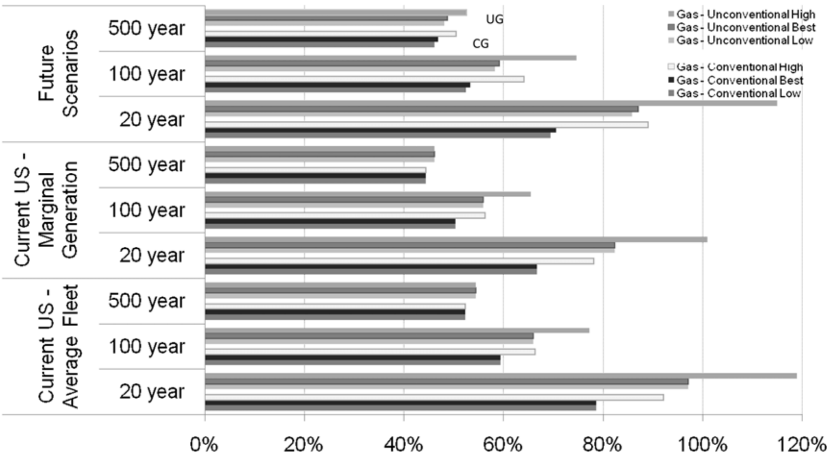

Figure 3. Greenhouse gas footprint of electricity from conventional and unconventional gas, relative to that of coal (defined as 100%). Results are expressed as a percentage of coal emissions and are derived from combustion emissions intensities in table 6 (kg CO_2e kWh^{-1} for gas normalized to kg CO_2e kWh^{-1} for coal). Results shown for GWP timescales of 20, 100, and 500 y. Reference coal emissions are taken from parallel assumptions (GWP, technology, etc).

Table 7. Summary of greenhouse gas emissions from unconventional gas, conventional gas, and coal for the US, assuming mid-range scenarios and 100 y GWP.

	Summary; mid-range scenarios, 100 y GWP		
	CG	UG	Coal
Current US—average fleet			
Combustion emissions intensity (kg CO_2e kWh^{-1})	0.561	0.623	0.945
Combustion emissions intensity (per cent of coal)	59.4	65.9	100.0
Combustion emissions intensity (increase versus CG) (%)	0.0	11.0	68.4
Current US—CGT generation			
Combustion emissions intensity (kg CO_2e kWh^{-1})	0.476	0.529	0.945
Combustion emissions intensity (per cent of coal)	50.4	55.9	100.0
Combustion emissions intensity (increase versus CG) (%)	0.0	11.0	98.5
Future technology			
Combustion emissions intensity (kg CO_2e kWh^{-1})	0.461	0.512	0.866
Combustion emissions intensity (per cent of coal)	53.3	59.1	100.0
Combustion emissions intensity (increase versus CG) (%)	0.0	11.0	87.7

advent of hydraulic fracturing techniques may fundamentally reorient national energy policies globally. As such, understanding the consequences of expanded unconventional gas production is an essential step to ensuring that this transition is managed rationally. While shale gas presents a number of questions and challenges, we have demonstrated that the fugitive emissions from the drilling process are very likely not substantially higher than for conventional gas. Table 7 presents the results of our mid-range assumptions for a 100 y GWP. In our calculations, a robust conclusion seems to be that even with high existing uncertainties in fugitive emissions from the hydraulic fracturing process, the greenhouse footprint of shale gas and other unconventional gas resources is about 11% higher than that of conventional gas for electricity generation, and still 56% that of coal. Moreover, if the spread in future fleet efficiencies between gas and coal increases over the coming decades, this differential from coal will continue to increase.

It is extremely important to note that this study's results derive from uncertain estimates of fugitive emissions from unconventional gas well development. We have reason to believe that better data collection and improved technology could substantially lower the estimates of emissions from a standard unconventional gas well, which would reduce (possibly substantially) the difference in GHG emissions between unconventional and conventional gas. However, without solid data it is impossible to say with certainty. Therefore, because the quality of publicly available data on fugitive emissions remains extremely poor, any sensible policy to evaluate the future of unconventional gas should include a transparent data collection program. This should cover a diverse set of geological situations, be conducted over the lifetime of sampled wells, and be published systematically and regularly.

Evaluated solely on the criterion of GHG emissions from electricity generation, shale gas is not likely to be substantially more polluting than conventional gas. Additional technologies to ensure reasonable capture of fugitive emissions may be able to reduce the disparity between the two resources further. Any regulatory standard that classifies conventional gas as a source of 'clean energy' should therefore consider shale gas in this context; arguments that shale gas is more polluting than coal are largely unjustified. On the other hand, despite the promises of inexpensive, abundant, and relatively low GHG fossil fuel, unconventional gas technology poses other challenges if it is to become a truly 'clean' bridge fuel. As a new technology, its deployment has arguably outpaced the ability of the policy and scientific communities to understand and regulate the possible environmental and health consequences of the fracking process. These issues require serious attention but, should they be solvable, new generation from unconventional gas could deliver benefits similar to those of conventional gas.

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