SHALE GAS GREENHOUSE GAS FOOTPRINT REVIEW

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INTERNATIONAL ENERGY AGENCY

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Executive Summary

This analytical review was originally prepared as a discussion note for the executive committee of the IEA Greenhouse Gas R&D programme in response to concern resulting from publication in the USA of an academic paper claiming that methane emissions arising from the production of shale gas could be sufficient to make unconventional natural gas from that source more greenhouse intensive than coal. Such a claim runs counter to the conventional wisdom that converting an application from coal to natural gas invariably results in a reduction in the greenhouse gas (GHG) emission consequences of the application, particularly so for power generation.

This review has identified that there is a dearth of representative public domain data on the natural gas industry in general and on the shale gas industry in particular, with conflicting claims of appropriate assumptions. To assist with understanding the issues, a model has been developed for carrying out Full Fuel Cycle (FFC) analyses and a methodology has been developed to accommodate uncertainty. This model has been populated with illustrative data. This review has been prepared for IEAGHG as a Technical Note to share with a wider readership with the intent of providing a framework for discussion of the impact on GHG emissions from Natural Gas production.

This issue is set against an on-going background of disagreement between environmentalists, academics and the shale gas industry, particularly in the USA. That disagreement is principally focused on incidents of adverse impacts on groundwater quality and community amenity attributed to hydraulic fracturing (fracking). There are some jurisdictions, in the USA and elsewhere, that have imposed a moratorium on the use of that enabling technology pending a better general understanding of the associated environmental issues.

Although fracking for shale gas production is the focus of this study, the wider issues involved in comparing the FFC emissions from coal and gas fired power generation apply also to conventional gas production. The recent upsurge in the global use of natural gas, particularly in the USA, has given rise to increases in Liquefied Natural Gas (LNG) transportation of gas, the application of carbon capture and storage (CCS) to gas fired power generation and concerns about the global warming potential of methane. These wider issues are considered in this report.

Findings

The only significant difference identified between shale gas production and conventional gas production from a GHG perspective arises from the additional emissions associated with the fracking process at the well-site. Those additional emissions comprise methane as natural gas losses from the returning fracking fluid and CO_2 from the additional use of diesel in drilling and pumping equipment with lesser effects attributable to the liquid unloading process. The other precombustion GHG emissions associated with natural gas supply to power stations; i.e. processing losses and transmission losses, as well as the combustion emissions, are independent of the technology used to produce the gas at the well site or the geological origins of the gas.

Using reference case default assumptions, as discussed in detail in Appendix A, the well site GHG emissions from a shale gas operation are about 39% greater than from a conventional natural gas well. The corresponding overall precombustion GHG emissions from shale gas, including processing and distribution are about 17% greater than the equivalent precombustion GHG emissions from conventional gas. Since the combustion GHG emissions are also the same regardless of the source of the gas, the FFC GHG emission for shale gas are 2.7% greater than conventional gas FFC GHG emissions.

When precombustion emissions are taken into account, the 50% saving in combustion GHG emissions attributable to selecting natural gas instead of coal for a new base load power station is reduced to a 45% saving in the case of conventional gas or to a 43.5% saving when the gas is sourced from shale with fracking. The precombustion emissions add about 8% to the combustion emissions from coal fired power generation, whereas the precombustion emissions add about 18% (conventional) and 21.5% (shale gas) to the combustion emissions from gas fired power generation. These FFC GHG emission assessments are made on the basis of the default assumptions that are detailed in Appendix A. The reference cases use the Global Warming Potential (GWP) value of 25, no transport of natural gas as LNG, a low concentration of CO_2 in the source gas, minor migration of gas from wells and no application of CCS.

There is on-going debate about the appropriate GWP value for methane. The IPCC fourth assessment report defined values of global warming potential as 25 when considered over a 100 year time horizon and 72 when considered over 20 years. The IPCC also noted but did not quantify an aerosol effect, which might increase the GWP of methane to 105 over the 20–year timeframe. Table ES1 shows the impact of an elevated GWP factor on methane emissions from both natural gas production and coal mining.

Table ES1 – Impact of GWP on FFC GHG emissions from power plants

Kg CO_2-eq/MWh (saving compared with coal)	**NGCC with shale gas**	**NGCC with conventional natural gas**	**Supercritical coal power plant**
GWP = 25	460 (43.5%)	448 (45.0%)	814
GWP = 72	539 (39.0%)	511 (42.1%)	883
GPW= 105	595 (36.1%)	556(40.3%)	931

Conventional natural gas transmission is by pipeline. Own use of gas for booster compressors and pipeline losses are included in the assessment. However, there is increasing international trade in natural gas in the form of LNG, which incurs substantial own use of gas. Inclusion of LNG in the gas supply train would reduce the GHG emission saving from 43.5% to 36.2% for shale gas and from 45% to 37.8% for conventional gas.

If the natural gas resource contains significant CO_2 its GHG footprint will increase. The increase will normally be small, but the exceptionally high CO_2 content of Natuna gas (71%) would give power generated from that gas exactly the same GHG intensity as power generated from coal under the default assumptions of this study.

The migration underground of gas from wells that have a loss of well integrity, resulting in methane discharges to air, is difficult to quantify and is seldom monitored. A small contribution due to migration of gas from both conventional gas wells and shale gas wells is included in the default assumptions. However, emission of migrating gas at a higher rate that would not present a local environmental or safety issue could be a major contribution to the greenhouse gas footprint. The possible contribution from gas migration is the largest component of the uncertainty assessments that have been modelled.

Complete offsetting of the GHG advantage of switching from coal to gas for base-load power generation would only occur under a worst case combination of factors. For example, if GHG emission calculations are based on the 20-year GWP of 105 (with aerosol effect) and LNG transport is included in the gas supply train then coal and gas would be equivalent when the additional unaccounted fugitive loss of gas from a shale gas well is 4% of raw gas production; or about 3% in the case of a conventional gas well. The potential impact of gas migration losses is more significant for conventional gas wells than for shale gas wells because of the longer lifetime of conventional wells.

Precombustion GHG emissions associated with upstream production of consumer fuels depend on a large number of variables that have a wide variability and uncertainty. The issue of uncertainty is addressed in this study by identifying a likely range for each of the assessment parameters discussed in Appendix A. A composite uncertainty range is then calculated as shown by error bars. Uncertainty ranges are proposed in the detailed assessments presented in Appendix A. The composite uncertainty indicates that the indicative precombustion emission estimates under the default set of assumptions are -40% to +60% for shale gas; -40% to +140% for conventional gas; and +/-60% for coal. The higher upper uncertainty bound for conventional gas is due to the possibility of higher potential migration losses.

The GHG footprint of power generation can be reduced by the installation of CCS on the power station to reduce the combustion emissions. However, the precombustion GHG emissions are not amenable to reduction with CCS and are actually increased because more fuel is required to accommodate the energy penalty of CCS. Hence, when considered on a FFC basis, the application of 90% CCS to an NGCC power plant burning shale gas would result in a net FFC GHG emission reduction of 70%. In the case of conventional gas the FFC GHG emission reductions corresponding to

90% CCS would be 72%. Using the assessment basis of this study, a coal fired power plant with 90% CCS would have a net FFC GHG emission reduction of 79%.

Conclusions

The IEA World Energy Outlook states *"We estimate that shale gas produced to proper standards of environmental responsibility has slightly higher "well to burner" emissions than conventional gas."* The analysis in this study quantifies that elevation in overall GHG emissions attributable to fracked shale gas as 2.7%.

The 1:2 GHG advantage of gas over coal for base load power generation is partly offset when precombustion GHG emissions are taken into account. When the gas is sourced from shale with fracking, that GHG advantage of gas over coal would be reduced to 1:1.77.

There is major variability and uncertainty in the assessment of precombustion emissions. Under a worst case combination of circumstances the GHG advantage of gas over coal for power generation might be completely lost. One example is the use gas from the of Natuna gas field, which contains 71% CO_2. Another example would involve the use of a high GWP factor combined with transport of gas as LNG and about 4% of production lost as fugitive emissions at a shale gas well site.

Precombustion emissions also adversely impact the benefit of adding CCS to power plants because precombustion emissions cannot be captured. In the case of a gas fired based load power station, the installation of 90% CCS would yield an overall reduction in FFC GHG emissions of about 70%.

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1. INTRODUCTION

A special report (IEA 2011) accompanying the IEA World Energy Outlook 2010 asked "Are we entering a golden age of gas?" That detailed report built a "Golden age of gas" scenario, which quantified global demand and supply pathways. The IEA report stated: -

- The factors driving natural gas demand and supply increasingly point to a future in which natural gas plays a greater role in the global energy mix.
- When replacing other fossil fuels, natural gas can lead to lower emissions of greenhouse gases and local pollutants.
- The global natural gas resource is vast and widely dispersed geographically.
- Unconventional natural gas resources are now estimated to be as large as conventional resources.
- Unconventional gas now makes up about 60% of marketed production in the United States.
- Use of hydraulic fracturing (fracking) in unconventional gas production has raised serious environmental concerns and tested existing regulatory regimes.
- Based on available data, we estimate that shale gas produced to proper standards of environmental responsibility has slightly higher "well to burner" emissions than conventional gas.

In contrast, a paper by Professor Bob Howarth from Cornell University (Howarth, 2011) suggests that surface plant methane emissions associated with fracking for shale gas production are at least 30% greater than, and perhaps more than twice as great as, those from conventional gas. Howarth (2011) also estimates that the Greenhouse Gas (GHG) footprint of shale gas can be comparable with that of coal when considered over the conventional 100-year timeframe, when an increased Global Warming Potential value due to consideration of aerosol effects is used. When considered over a 20-year time frame with the higher Global Warming Potential (GWP) for methane, Howarth, 2011 indicates that the greenhouse footprint of shale gas obtained with fracking could possibly be more than twice as great as the typical greenhouse footprint of coal under worst case assumptions.

The United States Environmental Protection Agency (USEPA) is charged with reporting the US Greenhouse Gas (GHG) inventory to the UNFCCC secretariat. In order to carry out that duty, the USEPA, with very little industry data, developed a methodology, published in 2010, for assessing the additional methane emissions arising from the completion of unconventional gas wells. That methodology derived a natural gas emission factor, which was not challenged by the shale gas industry at the time, of 9,175 Mscf[1] (260 thousand normal cubic metres) per well completion using fracking; arising primarily from the flowback of fracking fluid.

In August 2011 a private report "Mismeasuring Methane" from IHS CERA (2011) was published, which examined the basis of the USEPA methodology and concluded

[1] Mscf = Thousand standard cubic feet

that the key emission factor of 9,175 Mscf per well completion was three times overestimated compared with industry best practice.

In March 2012 a workshop was hosted in Arlington by IPIECA to discuss the issues surrounding greenhouse gas emissions from natural gas production. The principal conclusion from that workshop is that there is a need for more monitoring of actual discharges of methane from completion and production of conventional and unconventional gas wells. Programmes are being put in place by the US gas industry to accumulate data.

In April 2012 the USEPA inventory of greenhouse gas emissions, which included an analysis of methane emission from natural gas production, showed half of that emission estimate (before reductions) as arising from liquid unloading. Liquid unloading is a routine production procedure that periodically uses production gas to blow excess infiltrated water out of the gas well, when needed. The liquid unloading procedure can be used throughout the life of a gas well.

In June 2012 the American Petroleum Institute (API) and the American Natural Gas Association (ANGA) produced a report *"Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production"*(API 2012a). This report uses a database of information on 91,000 gas wells. It claims that losses from liquid unloading are very much less than estimated by EPA.

In September 2012 a further workshop was held in which the methodologies of the USEPA were compared with those of the API/ANGA. On some key issues an order of magnitude difference remained between the consequences of these methodologies.

These papers and reports revealed that the precombustion emissions of methane from shale gas fracking operations and conventional natural gas production operations, depend on a many uncertain variables. This note presents analysis using a scoping model for assessing the relative Greenhouse footprints of conventional natural gas and unconventional natural gas and presents it in the context of the alternative Global Warming Potentials. The analytical model also extends the analysis of the shale gas greenhouse footprint to include consideration of the use of natural gas in the context of power generation with and without carbon capture and storage (CCS) and consideration of the full fuel cycle greenhouse footprint of coal-fired power generation with and without CCS. Furthermore the model provides scope to consider issues not assessed in the Howarth paper or the industry analysis including consideration of transport of natural gas in the form of Liquefied Natural Gas (LNG) and discharges of methane to air arising from migration of gas from gas wells with compromised well integrity. The model assumptions, default values and likely ranges of variation are documented in detail in Appendix A.

2. MODELLING METHODOLOGY

For assessment with FFC methodology[2] a stepwise pathway for energy from primary source to the consumer's equipment needs to be defined. Figure 1 shows an illustration of the components of the FFC analysis for shale gas. These sources are discussed and quantified in Appendix A. The emissions from fracking flowback fluid (b) only apply to shale gas that is produced from wells that have been fracked and does not apply to conventional gas production. The local distribution losses (h) from low pressure reticulation of gas to domestic and small commercial consumers does not apply to gas consumed for base load power generation because the power plant would be directly connected to high pressure gas transmission pipeline. In the case of coal-fired power generation there would be a similar step-wise assessment pathway including coal seam methane discharges from the mine, fuel use for the mining operation and fuel use for coal transport to the consumer.

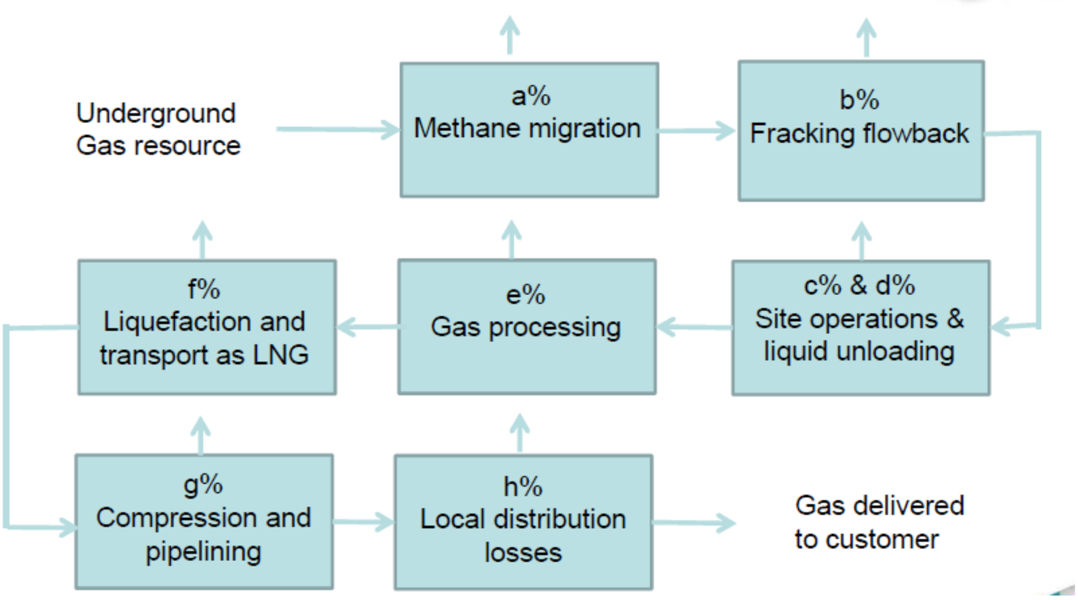

Figure 1 Compounding of shale gas pre-combustion emissions

Pre-combustion/Combustion emission ($CO_{2\text{-}eq}$) =
$(1+a)*(1+b)*(1+c+d)*(1+e)*(1+f)*(1+g)*(1+h)-1$

The spreadsheet model used in this assessment has been constructed to allow for setting of alternative input assumptions for exploration of sensitivity to parameters and definition of step-off cases. In addition, each of the input parameters and assumptions is defined with a default value that can be updated as alternative data becomes available. The input parameters are all in metric units, but most of the internal calculations are in traditional US units so that the actual values can be easily

[2] Full Fuel Cycle (FFC) methodology is an assessment that includes all discharges of CO_2 and methane arising from the precombustion and combustion of the fuel on as cradle-to-grave basis. However, the FFC methodology does not include any assessment of the embodied energy in equipment, as would be included in a full Life Cycle Analysis (LCA).

compared with information in the source literature on shale gas activities, most of which comes from the USA or is expressed in US conventional terms.

2.1 Dealing with Uncertainty

A key feature of the model is dealing with uncertainty. For each of the input parameters a range is defined in terms of minimum and maximum values. In the case of addition of parameters, the corresponding probability values are simply added to give a probability value for the sum. In the case of multiplication of parameters the combined effect of uncertainty is determined as the weighted geometric average of the products of the minimum or maximum values and the default value.[3] This device avoids directly compounding worst case assumptions, which would give unreasonably pessimistic or optimistic scenarios. This approach to dealing with the combination of uncertainty is adopted in order to allow the model to be constructed in a single page spreadsheet format in order to maintain transparency of presentation of the calculations. This device allows the composite uncertainty in the calculated results to be estimated and presented as error bars on the results charts.

2.2 Fluid flowback emissions

A controversial parameter in the life cycle assessment of natural gas production is the methane emissions associated with the flowback of fluid from fracking operations. This parameter only applies to gas wells that have been fracked and the bulk of available data arises from shale gas well completions in the USA. The net discharge to atmosphere is determined as the unmitigated emission rate reduced by the extent to which gas from the flowback fluid is captured and flared, which is an emission reduction measure known as Green Completion.

The AEA (2012) report carried out a comprehensive literature review and identified a wide range of estimated values expressed on a consistent basis as shown in Table 1.

Table 1. Estimates of emissions associated with flowback per well completion

Source	**Unmitigated natural gas emissions**		**Fraction flared**
	'000 m^3 (Mscf)	**Range '000 m^3**	
EPA (2011)	257 (9,081)	20 to 560	51%
Howarth et al (2011)	2034 (71.873)	140 to 6800	0 to 51%
URS (2012|)	21 (742)	10 to 32	included
Jiang et al (2011)	603 (21,307)	39 to 1508	76%
EPA (2012)	312 (11,025)	173 to 330	90%
AEA (2012) base case	312 (11,025)	up to 396	15%

The lowest fracking flowback emission estimate is from a study by URS commissioned by the US natural gas industry and the highest estimate is worst case data considered by Howarth et al., which differ by two orders of magnitude.

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[3] e.g. $\text{maxAB} = \exp\left[\frac{\ln(\text{maxA} * \text{meanB}) * \ln(\text{maxA} / \text{meanA}) + \ln(\text{maxB} * \text{meanA}) * \ln(\text{maxB} / \text{meanB})}{\ln(\text{max A} / \text{meanA}) + \ln(\text{maxB} / \text{meanB})}\right]$

In order to attempt to address the large uncertainty in the emissions associated with fracking flow back fluid, this report attempts to take an analytical approach to the determination of methane emissions. Two gas transport mechanisms are considered; natural gas dissolved in fracking flowback fluid and gas entrained with fracking flowback fluid

The estimation of gas dissolved in flow back fluid is based on the difference between the solubility of methane in water at down-hole temperature and pressure conditions and the solubility of methane at surface conditions. It is assumed that the discharged flow back fluid will be supersaturated in methane and that that methane will effervesce from the fluid in the flow back fluid collection pond.

The estimation of gas entrained with flowback fluid is based on a linear increase from nothing to the initial gas production rate over the flow back fluid production period. The entrained gas can potentially be separated from the flowback fluid and flared, so an additional considered parameter is the fraction of entrained gas that is flared.

The parameters required to carry out these calculations are identified and quantified in Appendix A. Maximum and minimum values for each of the parameters are also suggested and, using the uncertainty methodology described above, the resulting fracking fluid flowback emissions are calculated. For comparison with the data in Table 1, the calculated parameters developed for this report are a default value of 71 thousand m^3 (2495 Mscf) within the range 50 to 100 thousand m^3 per well completion.

2.3 Gas migration external to the well

Another controversial source of greenhouse gas emissions to atmosphere from natural gas production, quantified in this report, is methane discharges to air external to the gas well arising from methane migration resulting from loss of well integrity. This issue is discussed at length in Appendix A.9. Methane migration emissions, which are essentially unquantifiable, are generally assumed by others to be trivial, are not considered by most authors and are only included in inventories in a catch-all category of “other fugitives”. The AEA (2012) report identifies the potential for such emissions, but does not attempt to quantify them and notes that such emission apply equally to conventional and unconventional sources of natural gas.

In this study it postulated that such emissions might be generally underestimated and that significant greenhouse gas emissions might arise due to migration and dispersion of gas from leaking gas wells at rates that do not present local environmental or safety issues.

3. ILLUSTRATIVE ANALYSIS

This section attempts to provide quantified assessments to illustrate the contributions to pre-combustion emission of GHGs from the steps in natural gas production, and delivery. A comparison with coal is also made. There is substantial variability between cases in the real world and not all fuel supply routes will include contributions from all steps. The following charts are produced using a model that is based on the assumptions discussed and quantified in Appendix A. Where possible the assumptions set out in Appendix A are founded on information derived from the referenced technical literature. However, for some of the assumptions suitable representative source data is unavailable or conflicting or unknown, so values are proposed as a basis for discussion.

Figure 2 Gas vs. coal with and without CCS

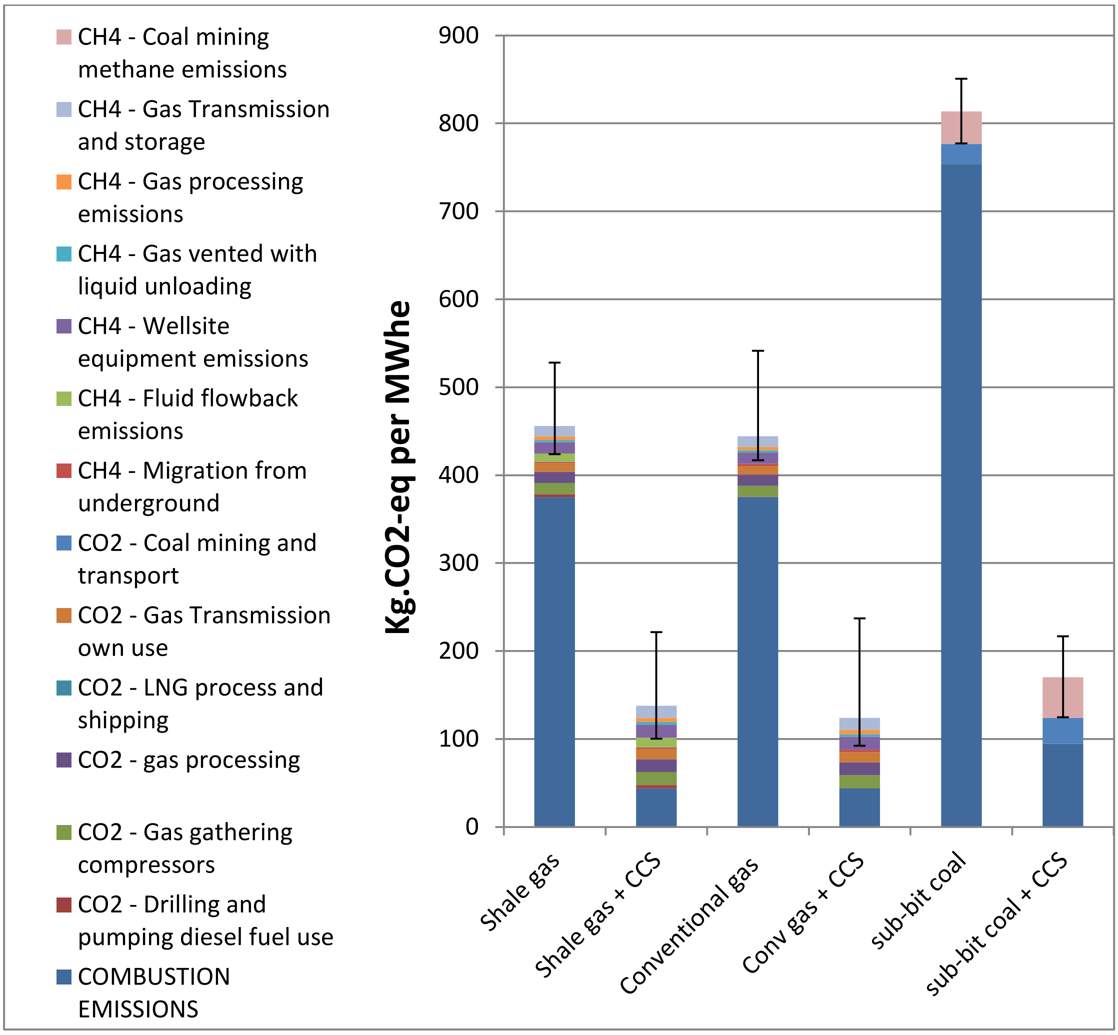


Figure 2 shows a comparison under the default assumption of the FFC GHG greenhouse emissions arising from the use of shale gas, conventional gas and coal with and without the inclusion of 90% carbon capture. The data corresponding to Figures 2 and 5 to 7 are presented in Appendix B.

When considered from this big picture perspective the additional fugitive methane emissions attributable to fracking that is used to produce shale gas are fairly small.

Figure 3 Shale gas precombustion emissions

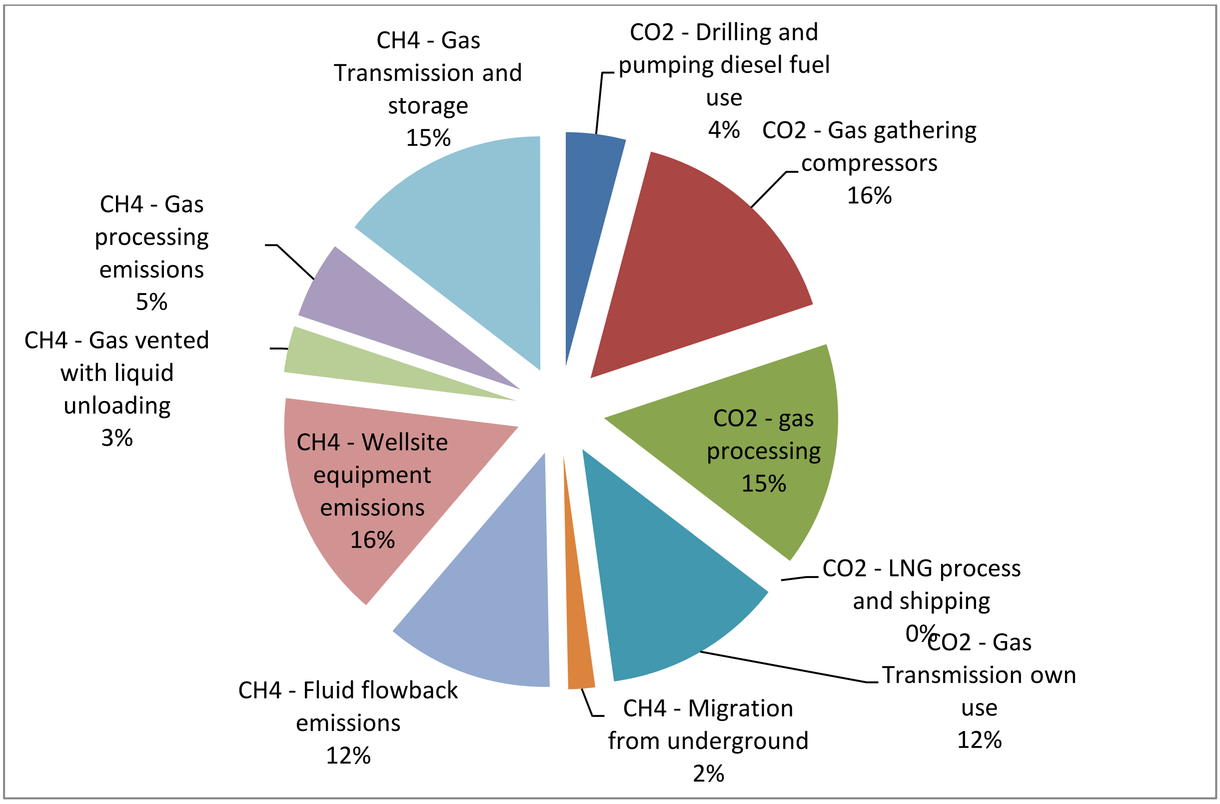
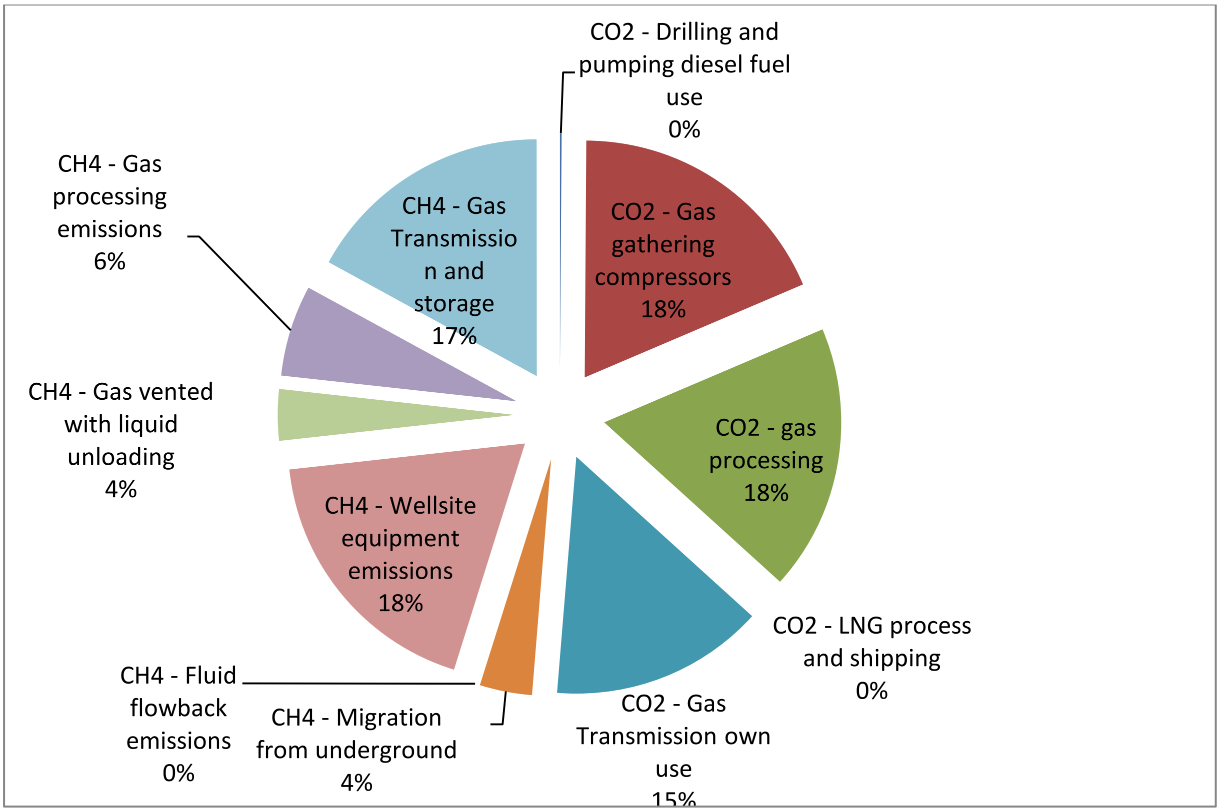


Figure 4 Conventional gas precombustion emissions



Figures 3 and 4 show the default contributions to precombustion emissions from the supply of shale gas and conventional gas. The default cases exclude transport as LNG.

Figure 2 shows the major reduction in GHG emissions that would arise from the installation of CCS on the power station. However, that greenhouse benefit is reduced when the bigger picture of FFC emission is considered.

Figure 5 Impact of GWP on precombustion emissions

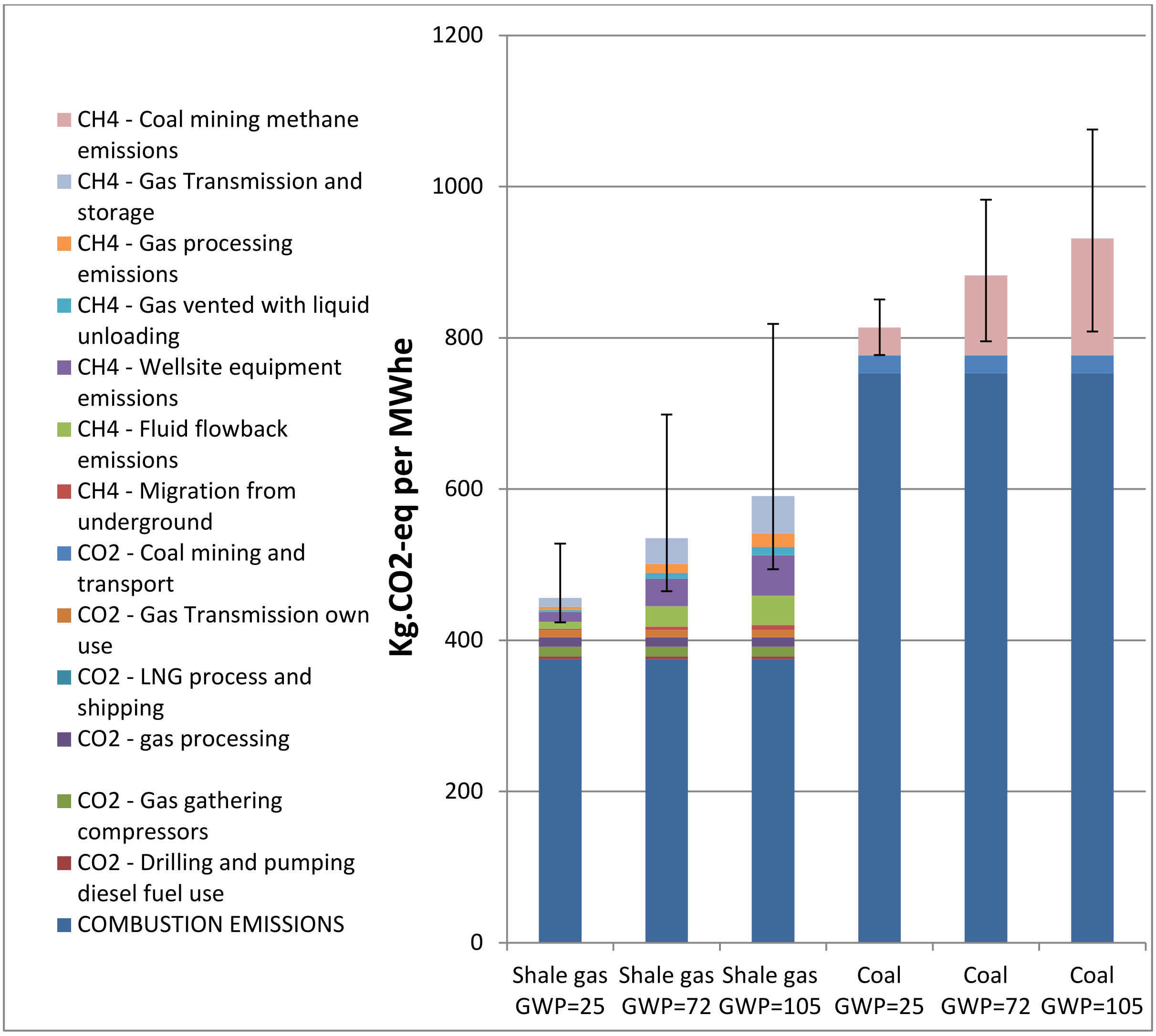


Figure 5 shows the impact on the FFC GHG emissions from power generation with coal and shale gas under two alternative GWP scenarios. It can be seen that the GHG emissions from shale gas are more sensitive to GWP than the coal bed methane emission from coal mining.

The headline worst case publicised by Prof Howarth (2011) used the GWP factor of 105, but had several differences from the assessment used in this study. For example, Howarth's paper did not take account of "green completion"[4] of shale gas wells reducing fugitive emissions, nor the power generation efficiency benefit of gas over coal, nor the impact of a

[4] See discussion of Green completion for reduced emissions from fracking operations in Section A13.

high GWP value on coal mining emissions. However, Howarth's paper also did not consider the impact of transport of gas as LNG or the discharge of methane due to gas migration from leaking wells. The indication in Figures 2 and 5 that the GHG benefit of gas over coal is reduced but not eliminated when precombustion emissions are taken into account, being at variance with Howarth's bottom line conclusion, is due to the many differences in assumptions.

Figure 6 Impact of LNG on Precombustion Emissions and comparison of Natuna gas with coal for power generation

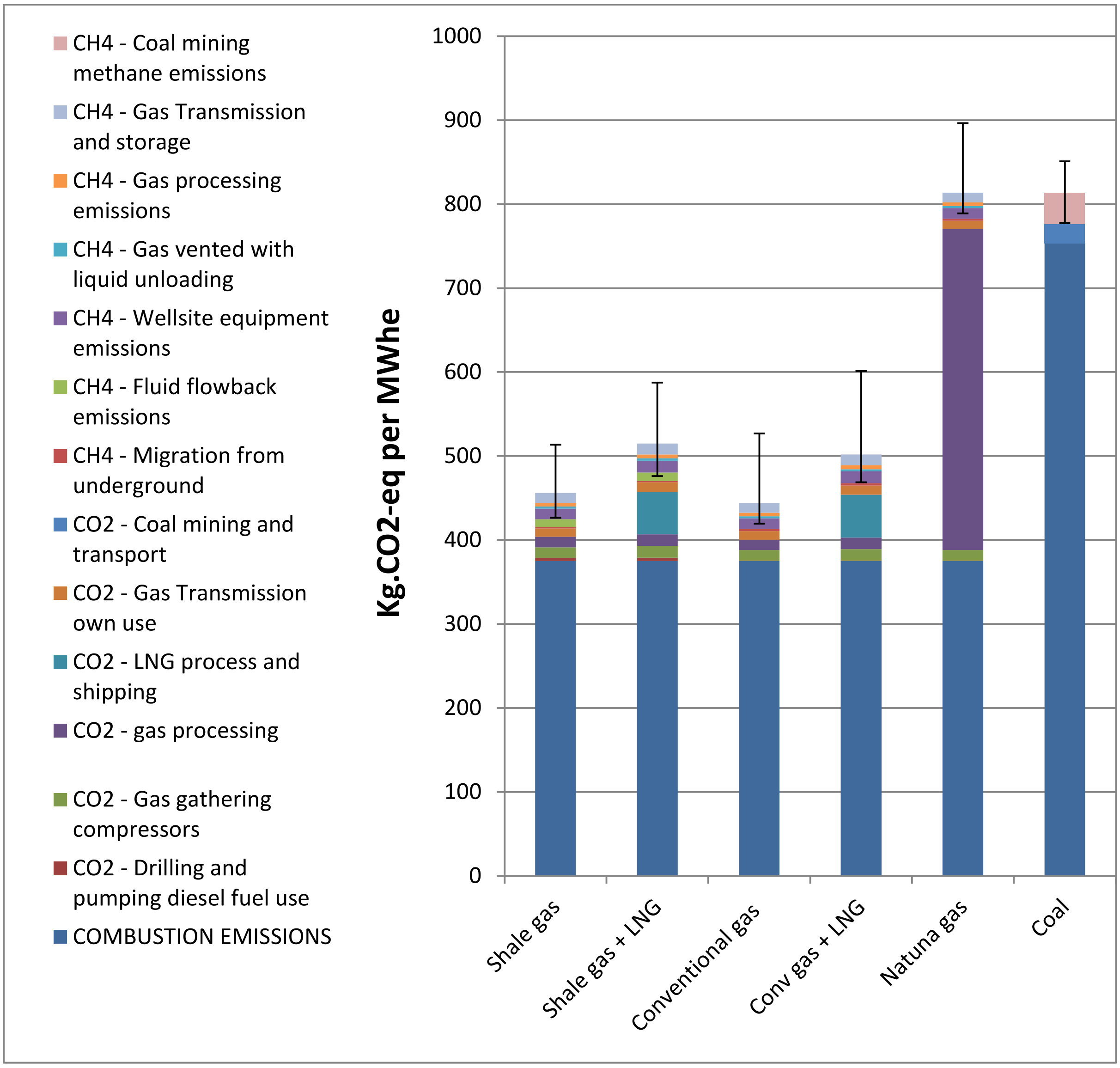


Figure 6 illustrates the adverse impact on FFC emissions of two factors not considered by Howarth, the transport of gas as LNG and the use a natural gas (Natuna) with an exceptionally high CO_2 content, both of which significantly impact CO_2 emissions rather than methane emissions.

Until about a year ago shale gas was only considered as a supplement for the domestic US market, but in recent months there have been indications that US shale gas may potentially be exported in the form of LNG. The default data in Appendix A suggest that transport of gas as LNG adds about 14% to its overall GHG footprint.

In the exceptional case of the large Natuna gas resource in the South China Sea with 71% CO_2 content, if that CO_2 is stripped and vented, as is the common gas processing practice, the GHG footprint of the resulting gas used for power generation would be about the same as that of power generation from coal.

Figure 7 Worst case combinations of factors

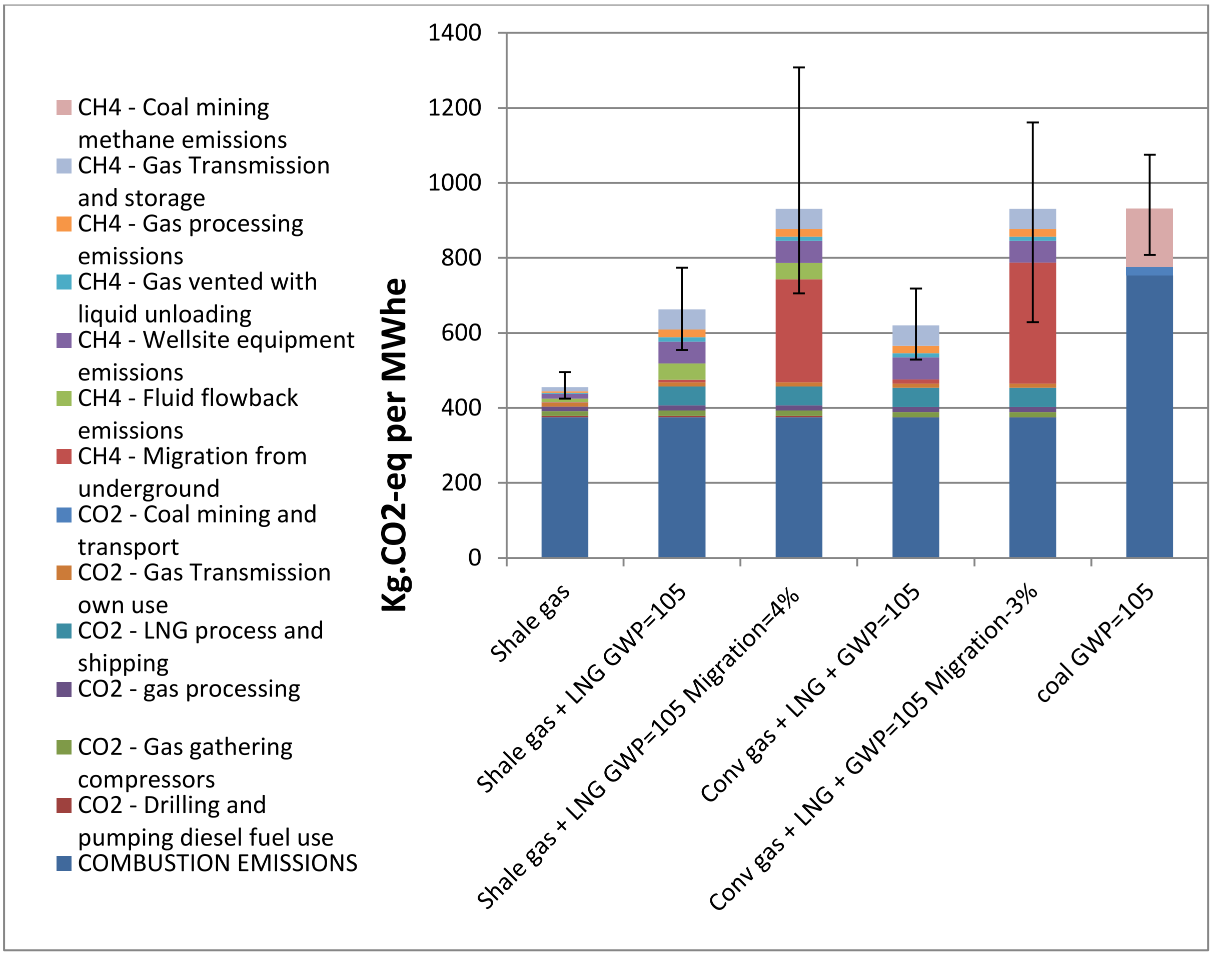


Figure 7 explores circumstances that would give rise to the GHG advantage of gas over coal for power generation being eliminated by precombustion emissions. The extent of additional methane migration that would be required to make the FFC emissions equal has been calculated on the basis of using the GWP scenario of 105 in combination with transport of gas as LNG. These calculations indicate that that situation would arise if the methane migration from a shale gas well was 4% of the gas production; or 2.85% in the case of a conventional gas well.

As discussed in Section A9, an air quality investigation in Colorado has suggested the possibility of undocumented methane leaks from gas wells of that magnitude being observed in practice, which gives the scenarios shown in Figure 7 some credibility. The error bars also show that there is scope for other scenarios to be considered in which gas-fired power generation completely loses its GHG advantage over coal fired power generation.

This illustrative analysis provides a framework for further investigation and discussion and points to the need for additional monitoring and data gathering to reduce the uncertainty in FFC GHG analysis.

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APPENDIX A

MODEL ASSUMPTIONS AND DEFAULT VALUES

A1. Methane Global Warming Potential (GWP)

The relative effects of methane (CH_4) and carbon dioxide (CO_2) on the global climate is controversial. CH_4 breaks down in the atmosphere, with a half-life of about 7 years. In contrast CO_2 is stable in the atmosphere, but is slowly removed, principally by net dissolution in the oceans over centuries. The relative effects of CO_2 and CH_4 on the global climate are strongly dependent on the time period over which the effects are considered.

The agreed GWP of methane that is used for international carbon accounting is 21; i.e. 1 tonne of CH_4 has the same radiative forcing effect in the atmosphere as 21 tonnes of CO_2. That GWP factor of 21 was determined in the Second Assessment Report (SAR) (IPCC 1995) and relates to consideration over a 100-year time horizon.

The IPCC Fourth Assessment Report (FAR) (IPCC 2007) took account of more recent research and determined two methane GWP values; 25 over a 100-year time horizon and 72 over a 20-year time horizon. The IPCC FAR report did not make a recommendation as to which time period should be used.

The IPCC FAR also discussed, but did not quantify, the additional mechanism of an aerosol effect which enhances the radiative forcing of CH_4. That aerosol effect was quantified by Shindell (2010) as increasing the GWP of methane to 33 over a 100-year time horizon and 105 over a 20-year time horizon. The controversial paper by Prof Bob Howarth (2011), which concluded that shale gas could be more greenhouse intensive than coal, used the GWP of 105 to reach that conclusion.

In view of the highly controversial and significant nature of the basis of assessment of the GWP of methane the GWP value of 25 is adopted as the default value in this model and the values of 72 and 105 are considered in sensitivity cases. The AEA (2012) study was also based on a GWP value of 25 for methane.

	Default	**Step-off case 1**	**Step-off case 2**
GWP	25	72	105

A2. Consumer fuel CO_2 emission factors

Nominal pipeline gas and sub-bituminous coal power station fuels are defined to establish an assessment basis. In addition a CO_2 emission factor for raw gas is defined, based on the compositions in Table A7. The default combustion emission factors are: -

		Raw gas	Pipeline gas	Coal
Combustion emission factor	Kg.CO_2/GJ-lhv	59.562	57.945	92.080

A3. CCS Energy penalties

Post combustion capture of CO_2 from flue gas with the conventional MEA solvent or with an advanced solvent involves extraction of steam from the power station steam cycle for use as a source of heat for regenerating the solvent. As a result the overall efficiency of power generation is reduced. That efficiency penalty can be expressed as a loss of electricity output per tonne of CO_2 captured.

A 2006 IEAGHG Technical study (IEAGHG 2006) defined reference case studies for 85% post combustion CO_2 capture with MEA solvent from a natural gas combined cycle power station and an Ultra Supercritical pulverized fuel coal fired power station. The corresponding reductions in net power generation efficiencies were from 55.6% to 47.4% for the gas fired plant and from 44.0% to 34.8% for the coal fired plant. The corresponding electricity production penalties were 462 kWh/tonne of CO_2 captured for the gas plant and 327 kWh/tonne CO_2 for the coal plant, with a higher CO_2 concentration. These data indicates that the energy penalty for post-combustion capture from gas turbine flue gas is about 1.4 times greater than from coal fired power plant flue gas.

Whilst these factors are based on 85% CO_2 capture, an alternative scenario would be 90% CO_2 capture. In that case the energy penalty per tonne of CO_2 captured would probably be greater. The model is configured to accommodate such alternative scenarios.

A 2011 IEAGHG conference report (IEAGHG 2011) on advanced post-combustion solvents concluded "*Energy required for CO_2 capture from coal is settling into a range of 200-250 kWh/tonne CO_2. KS-1, piperazine, AMP/PZ, MDEA/PZ are some of the superior solvents.* This conclusion indicates that advanced solvents might reduce the energy penalty for coal fired generation by 25% to 35% compared with the benchmark MEA solvent.

A 2012 IEAGHG Technical Study (IEAGHG 2012) revisited the post- combustion capture of CO_2 from a gas fired power station. One case was based on the use of a conventional MEA solvent and another case was based on the use of an advanced proprietary solvent. The corresponding reductions in net power station efficiencies were from 58.9% for a high performance natural gas combined cycle power plant to 51.0 % when conventional MEA solvent is used and to 52.0% when an advanced proprietary solvent is used. The corresponding electricity production penalties are 445 kWh/tonne CO_2 with MEA solvent and 389 kWh/tonne CO_2 with a proprietary solvent. This indicates that advanced solvents might reduce the energy penalty for gas fired generation by 12.5% compared with the benchmark MEA solvent.

Based on these sources, the following non-specific energy default penalty values are assumed: -

kWh per tonne CO_2	Minimum	Mean	Maximum
Gas turbine exhaust	350	420	500
Coal boiler flue gas	200	300	350

A4. Power Plant Efficiencies

Default power plant efficiencies for gas and coal fired power stations are 55.6% lhv and 44.0% lhv respectively, as reported in IEAGHG 2006/8. The gas fired power plant efficiency corresponds to a state of the art combined cycle power station. The coal fired power station corresponds to a state of the art pulverized coal power station with an ultra-supercritical steam cycle. The corresponding efficiencies with CCS are determined from the above energy penalties.

		NGCC Gas	PF USC Coal
Power plant efficiency w/o CCS	% lhv	55.6%	44%
Power plant efficiency with 85% Carbon capture	% lhv	47.4%	34.8%

A5. Depth of Gas Wells

The depth of gas wells vary greatly between locations. However shale gas resources are generally deeper than conventional natural gas wells. The depth of well parameter is primarily used in the model to determine down hole temperature and pressure conditions and is therefore the vertical depth of the resource being accessed below the surface. The default well vertical depth is assumed to be 1000m for conventional gas wells and 2000 m for shale gas wells, with a nominal; range from a half to double those depths.

For estimation of the diesel requirements for drilling, and the finished well volume, in the case of a typical shale gas well, an additional parameter needs to be defined, which is the length of the lateral that is drilled horizontally through the shale formation. A default value of 2000 metres is assumed for the length of the lateral, within a range of half to double that length.

Well depth	Minimum	Mean	Maximum
Conventional well	500 m	1,000 m	2000 m
Shale gas well vertical	1,000 m	2,000 m	4,000 m
Lateral well extension	1,000 m	2,000 m	4,000 m

A6. Diameter of Gas Wells

The gas well inside diameter is used to determine the volume of gas in the well that is potentially released during liquid unloading events, using the USEPA Greenhouse gas reporting equation W-8 from 40 CRF 98 subpart W as described in the API/ANGA (2012) report. The API/ANGA (2012) survey reports gas well internal diameters for 51 groups of gas wells. Wells without plunger lifts are reported to have an average diameter of 4.53 inches within the range 3.65 to 10.75 inches. The wells with plunger lifts are reported to have an average diameter of 2.15 inches within the range 1.92 to 4.11 inches.

The use of plunger lift technology provides the opportunity for significantly reducing the proportion of liquid unloading gas discharge that is vented. Although a formula (W-9 in API/ANGA 2012) for calculating the liquid unloading emissions from wells using plunger lift technology is included in the API/ANGA (2012) report, the logic of that methodology is questionable. Therefore for the purpose of this model the potential liquid unloading emissions are determined on the basis of wells without plunger lifts and the potential benefits of plunger lift technology are represented in the parameter defining the probability that liquid unloading gas is vented, as described below.

The assumed range and mean value for well diameter are as follows: -

Well internal diameter	Minimum	Mean	Maximum
Wells without plunger lifts	93 mm	115 mm	273 mm

A7. Well Shut-in Pressure

The well shut in pressure is the pressure developed in the well at the surface when the well is shut-in prior to a liquid unloading event. This pressure is used to calculate the volume of gas in the well that is potentially vented during liquid unloading. The API/ANGA (2012) survey reports gas well shut-in pressures for 51 groups of gas wells. The mean shut in pressure is 147 psig within the range 15 to 540 psig. The default assumed mean value and range and for shut-in pressure are as follows: -

Well shut –in pressure	Minimum	Mean	Maximum
Based on API/ANGA data	2 bar	11 bar	38 bar

A8. Average Gas Well Production Rates

A8.1 USEIA data

The average rate of production of gas over the lifetime of a gas well is a critically important parameter for relating methane emissions to methane production. This parameter varies greatly from well to well and declines markedly over the life of the well. The USEIA (2010) report provides data for oil and gas production segregated by well productivity, which ranges from 2.4 Mscf/d (68 m^3/day) to 85,000 Mscf/d (2.4 million m^3/day)[5]. Figure A1 shows the distribution of well productivities on the basis of number of wells (red solid line) and on the basis of the amount of energy produced (blue solid line). These plots show that about half of the wells produce less than 1000 m^3/day, whereas about half of the gas produced is from wells with individual productivities of 10,000 to 100,000 m^3/day. This data source reports that overall in the USA in 2009, 461,388 gas wells produced 23,959 billion cu ft of gas, corresponding to an overall average flowrate for all US gas wells of 142 Mscf/day (4,028 m^3/day)

[5] Mscf – thousand standard cubic feet following the US convention of "M" meaning a multiplier of one thousand. Hence under this convention "MM" would be used for a multiplier of one million.

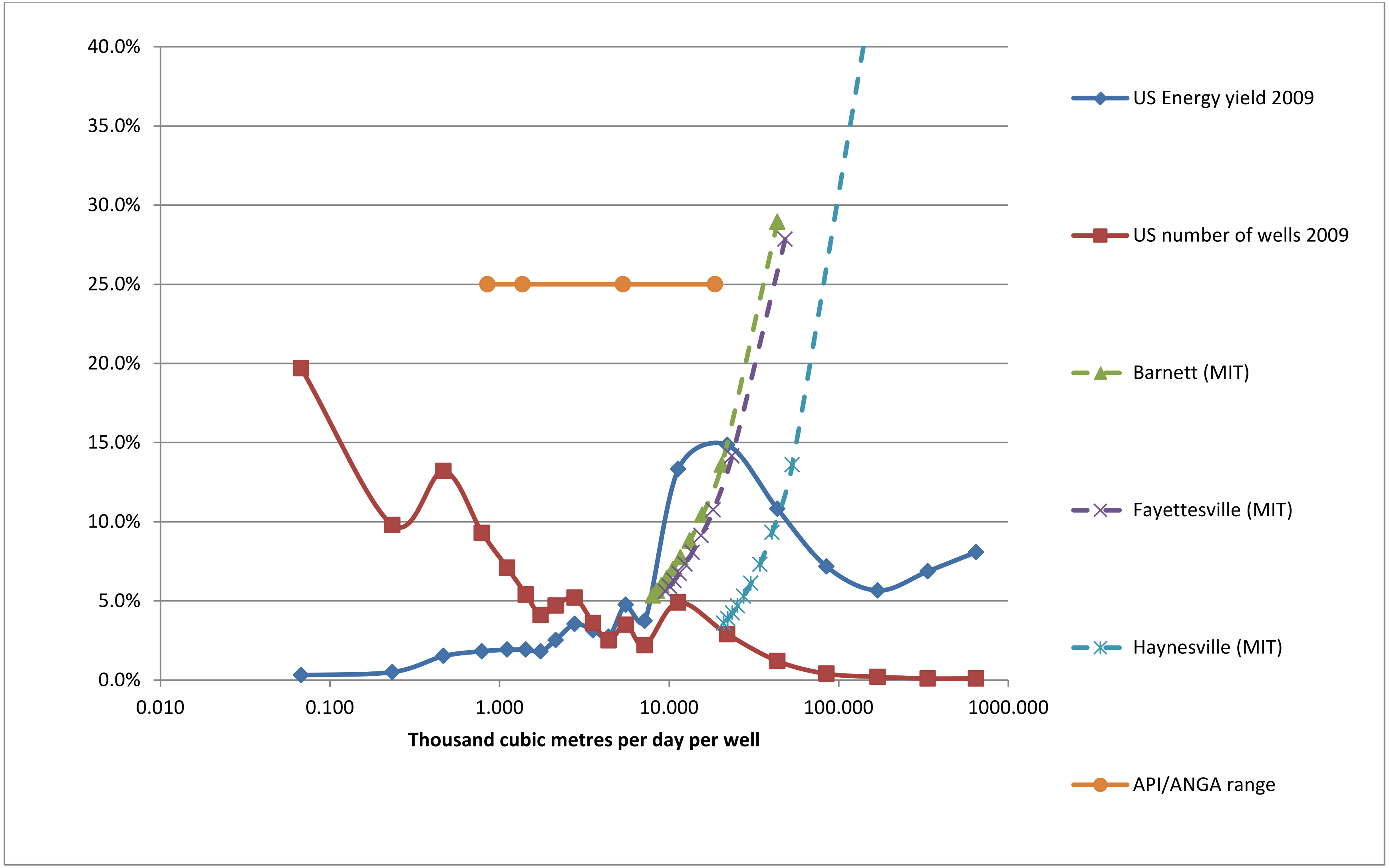


Figure A1 Well productivity distribution and comparison

Historical annual data from USEIA (2010) from 1995 to 2010 shows that the mean well productivity declined over that period from about 5000 m^3 per day to about 4000 m^3 per day during a period when the proportion of shale gas wells increase greatly, that evidence implies that on average shale gas wells have lower productivity than conventional gas wells.

A8.2 API/ANGA data

A survey of gas wells conducted for API/ANGA (2012) based on data for 2010/2011 included analysis of 51 sets of data for liquid unloading segregated as convention and unconventional wells with and without plunger lifts. These data included estimates of average well productivity for each of the 51 groups of wells.

Table A1 Well productivity data from an API/ANGA survey

	Number of datasets	Average Mscf/day	Average m^3/day
Conventional wells without plunger lifts	7	30	850
Conventional wells with plunger lifts	5	48	1,370
Weighted average for conventional wells	12	38	1,066
Unconventional wells without plunger lifts	21	638	18,692
Unconventional wells with plunger lifts	18	189	5,352
Weighted average for unconventional wells	39	430	12.535

Although there is significant uncertainty concerning the definition of conventional and unconventional gas wells in the API/ANGA survey, and there is no information as to how far down the depletion curve the wells were, these data indicate that shale gas wells generally have significantly higher individual productivity than conventional gas wells, which is contrary to the evidence of the USEIA (2010) data as noted above)

A8.3 MIT data

Some of the uncertainty in shale gas productivity data is resolved in a recent report from Massachusetts Institute of Technology (MIT 2012) which is based on better defined data for 3,948 shale gas wells, of which almost half are in the Barnett shale play. Figures A2 and A3 show productivity decline curves for data from the Barnett, Fayettesville and Haynesville shale plays.

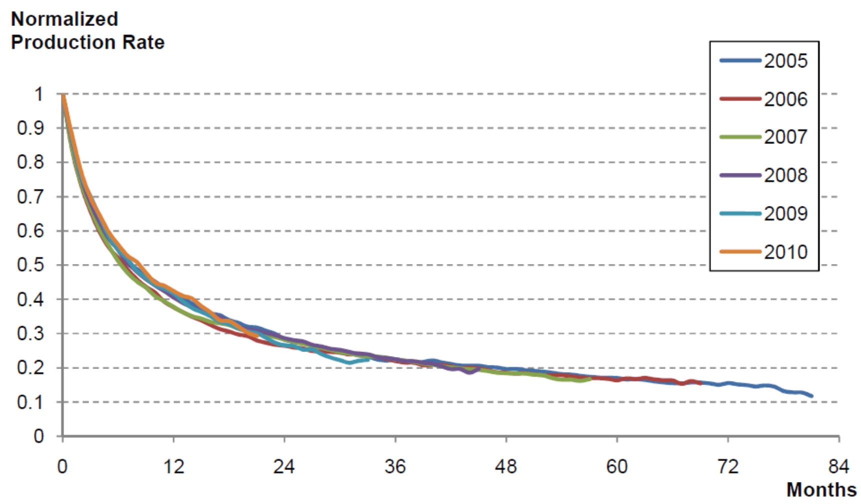


Figure S3: Normalized production decline characteristics for Barnett shale well vintages from 2005 to 201
(Source: (HPDI, 2012))

Figure A2 Productivity decline in Barnett

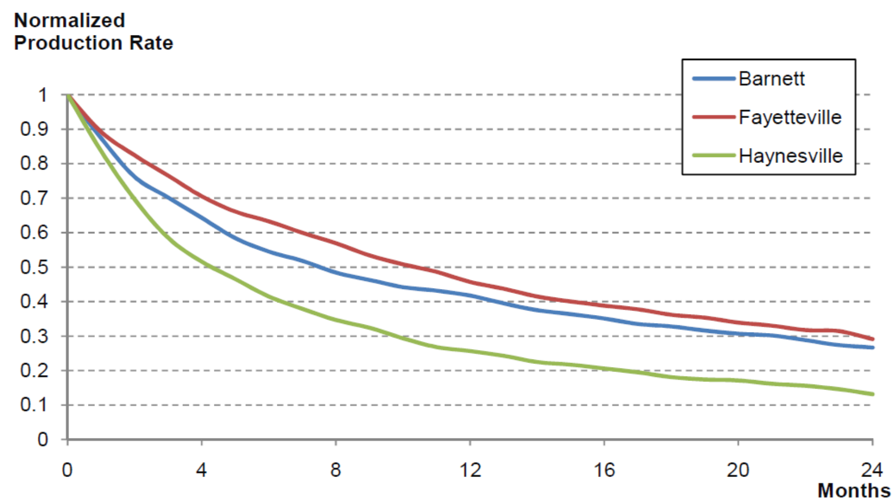


Figure S4: Normalized production decline characteristics for 2009 vintage horizontal wells in the Barnett, Fayetteville and Haynesville shale plays. (Source: (HPDI, 2012))

Figure A3 Decline curves for 3 shale plays

The analysis by MIT (2012) shows that after about 2 months of production at the initial production rate, the yield of gas falls off exponentially. Table A2 shows some initial production rates reported and production decline components derived from MIT (2012). Also shown in Table A2 are the corresponding average lifetime[6] production rates for wells with a lifetime of 5, 10 and 15 years and indicative data for generic shale gas and conventional gas wells.

Table A2 Initial and average well productivity data (MIT 2012)

	Initial production rate	**Decline exponent**	**Average lifetime production rate thousand m^3/day**		
	'000 m3/day		5 years	10 years	15 years
Barnett shale	61	-0.5	20.9	15.1	12.4
Fayettesville Shale	66	-0.48	23.8	17.4	14.4
Haynesville shale	262	-0.71	56.0	35.7	27.4
Generic shale gas	60	-0.5	20.7	14.9	12.3

The MIT data indicate ranges averaging to 40% to 172% of the initial production rate.

Figure A1 shows very wide variance of well productivity data; noting that the productivity data is on a logarithmic scale. In light of the foregoing analysis and discussion the average well productivity is determined according to the following formula; -

$$\text{Productivity} = \text{IPR} * \sqrt{2} * (\text{life}^{(1+\text{exp})}/(1+\text{exp}) - 2^{(1+\text{exp})}/(1+\text{exp})+2)/\text{life}$$

Where: - Productivity = Average lifetime production of gas (thousand m^3/day)

IPR = Initial production rate (thousand m^3/day)

Life = Well lifetime from completion to reworking (months)

Exp = Productivity decline exponent (negative fraction)

In summary, there is a large disparity in average lifetime gas well production between: -

- the USEIA (2010) data indicating lifetime average overall yield from all non-associated US wells declining from 5,000 m^3/d to 4000 m^3.day as more shale gas wells come on stream;
- API/ANGA data indications of 12,500 m^3/day for shale gas wells and 1,000 m^3/day for conventional wells; and
- MIT data indications of 15,000 m^3/day for shale gas wells.

For conventional wells the mean lifetime average productivity is assumed to be 3,000m^3/day as the midpoint between historical USEIA data and API /ANGA data. That average productivity

[6] The lifetime of a shale gas well is defined as the time from well completion to the first well reworking.

would correspond to an initial peak production rate of 10,000 m^3/day with a decline exponent of -0.33 and a well lifetime of 30 years.

For unconventional (shale gas) wells, the discrepancy indicates that the subsets of wells considered in the API/ANGA and MIT surveys are apparently the more productive shale gas wells and the USEIA data imply the existence of a large number of shale gas wells having a much lower productivity. Accordingly, for a generic shale gas well, the average productivity is assumed to be 5,000m^3/day. That average productivity would correspond to an initial peak production rate of 20,000 m^3/day with a decline exponent of -0.5 and a well lifetime of 10 years.

In order to reflect the wide variance of well productivity data in the model, minimum and maximum values for the input parameters are assumed based on the source data discussed above. The range of initial well production rates is assumed to be 0.4% to 1.72% in accordance with the MIT data. The range of shale gas well lifetimes is assumed to be 5 years to 20 years and conventional wells 10 year to 40 years. The variance of productivity decline exponents is assumed to be +/-0.1. Table A3 shows the data used in the model and the consequent average well productivities.

Table A3 Data for determination of average well productivity

Shale gas	**units**	**Minimum**	**Mean**	**Maximum**
Initial Production Rate	’000 m^3/day	8.0	**20**	34.5
Well lifetime before reworking	years	5	**10**	20
Productivity decline exponent		-0.40	**-0.5**	-0.6
Average productivity (calculated)	’000 m^3/day	1.1	**5.0**	16.3
Conventional natural gas				
Initial Production Rate	’000 m^3/day	4.0	**10**	17.2
Well lifetime before reworking	years	10	**30**	50
Productivity decline exponent		-0.23	**-0.33**	-0.43
Average productivity (calculated)	’000 m^3/day	0.62	**3.0**	13.0

Figure A4 shows the default productivity decline curves and the ranges used in the model corresponding to these default assumptions.

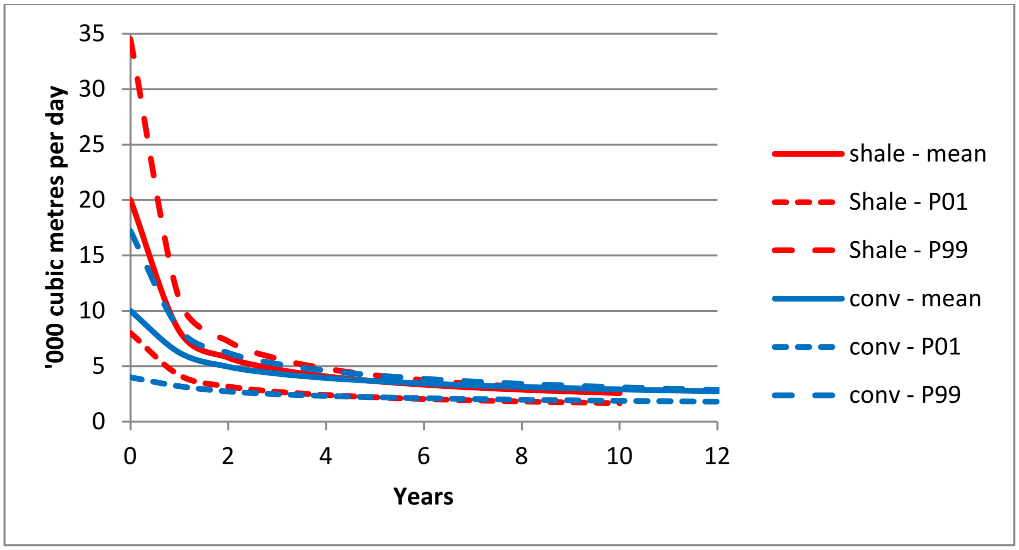


Figure A4 – Default productivity decline curves

A9. Gas Migration from below the Well site

The migration of methane from a leaking gas well, due to loss of well integrity, though the surrounding surface formation layers with subsequent discharge to air from the ground surrounding the wellhead is a controversial matter. Monitoring for such emissions to air is not normally carried out unless there is perceived to be either a safety hazard or a significant adverse local environmental effect or unless there is a monitoring requirement imposed by regulation. In the absence of routine monitoring there is no regular source of data on occurrence or quantity of methane migration from gas wells through the ground into the air. In the absence of data, the gas industry generally considers such emissions to be trivial and inconsequential. Where migration of natural gas is detected there is usually a default obligation to remedy the situation. However, remedial measures are costly and success is not certain. In the case of minor gas leakages, an attempt at well repair may not be given priority.

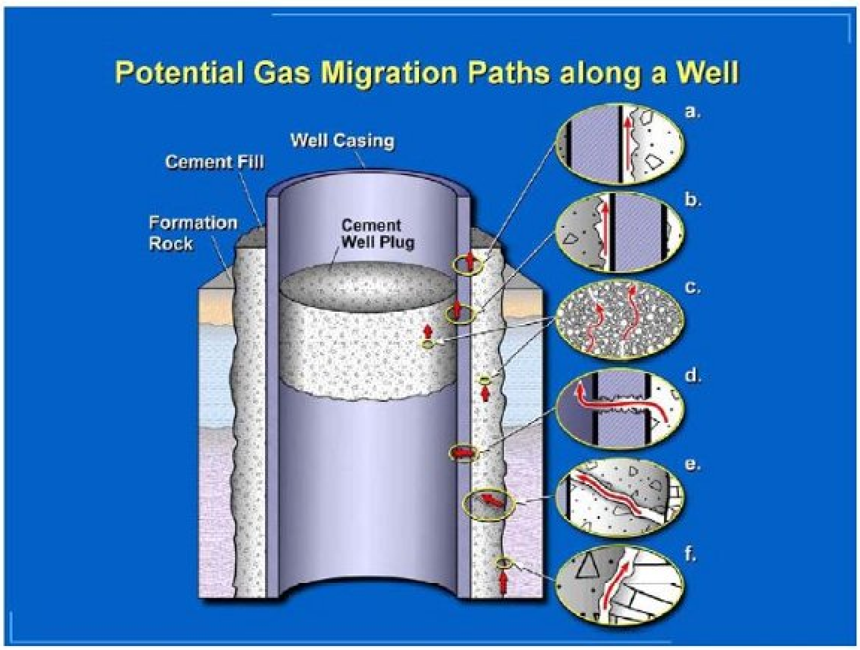
The main public concerns regarding underground natural gas migration from wells are contamination of groundwater and the potential for explosion hazard from pockets of methane collected in surface buildings. However, the concern of this report is quantification of the extent and scale of the contribution of gas migration leaks to the greenhouse footprint of gas production, which may be non-trivial even when there would be no local consequences of concern.

Whilst much of the popular literature focuses on leaks from hydraulically fractured shale gas wells, conventional wells are also subject to loss of wellbore integrity. For example, it is reported (Jenner 2012) that the infamous flaming faucet scene in the *Gaslands* movie has been traced to a conventional gas well not a shale gas well.

A9.1 Probability of gas migration occurring

A key objective of gas well construction is to ensure good well integrity so that none of the gas can escape into the surrounding formations. Well integrity is established with borehole logging procedures and if significant leaks are detected procedures can be carried out to repair the well. Loss of well integrity can arise from incorrect well construction or from well deterioration due to corrosion, or physical or thermal stress such as might arise from procedures such as hydraulic fracturing. Figure A5 illustrates potential gas migration pathways.

Figure A5 Potential gas migration paths along a well



Source: Alberta Energy Utilities Board

Watson (2009) described two types of gas leak due to loss of well integrity; Surface Casing Vent Flow (SCVF) and Gas Migration (GM) external to the casing. SCVF is contained and can be vented, flared or processed, whereas GM is inevitably a fugitive emission. Watson (2009) analysed data for Alberta and for a smaller test area where a monitoring regime was mandated. This analysis indicated that wells with SCVF comprised 3.9% of all wells in the general area and 9.2% in the test area. The detection of GM leaks was at 0.6% of wells in the general area and 5.7% of wells in the test area. The GM test consisted of boring small holes in the soil to a minimum depth of 50 cm in a test pattern radiating out from the wellbore. The holes were stoppered to allow gas to build up and a reading of the lower explosion limit was made to detect any combustible gas. That test regime resulted in a ten-fold increase in the detection of GM. Although the test is low cost, consequential remediation work would be very costly.

An oil and gas industry consultant (Loizzo 2012) suggested that some leakage typically occurs into the surrounding formations from about 20% of operating gas wells. A recent Canadian review paper (Nikiforuk 2013) suggests that loss of integrity of wells leading to leakage and migration of natural gas migration is a well documented chronic problem of the gas industry and suggests that up to 60% of all wells leak; increasingly so with age. Half of this high estimate is taken as an upper bound to the proportion of wells that leak, with the Watson analysis of GM leakage taken as a lower bound.

These considerations indicate that actual methane migration adjacent to gas wells might occur from about 20% of wells within the range of 6% to 30%.

A9.2 Scale of gas migration

Even in cases where methane migration is detected and investigated, the overall rate of methane discharge to air per gas well can only be estimated. The following considerations explore approaches to setting boundaries and to establishing a reasonable general estimate of the scale of gas migration from natural gas wells.

Analysis of accidents from natural gas storage leading to casualties or asset damage (Loizzo 2012) implies that a leak needs to be over 10,000 tonnes per year (38,000 Nm^3/day/well) to burn, explode or cause breathing problems. Methane is lighter than air so natural gas discharges to air rapidly disperse. During the fluid flowback stage of hydraulic fracturing process well-ventilated methane discharges to air can be as high as 8000 Mscf (226,000 m^3) over a 7 day period; i.e. 32,000 Nm^3/day/well. Green completion procedures are typically used in the USA to mitigate these emissions. In light of considerations discussed in this study, methane emissions from flowback fluid with mitigation measures are 2,400 Mscf per completion (i.e. about 10,000 Nm^3/day/well) in the reference case. These considerations set a very high safety-related benchmark as an upper theoretical limit on the potential for credible unmitigated methane discharges due to migration from loss of well integrity. These considerations do not suggest that undetected methane migration as high as 10,000 Nm^3/day/well could actually occur.

A study by NOAA (Pétron 2012) identified unexpectedly high concentrations of atmospheric methane in Weld County, Colorado, downwind from extensive gas production activities in the Denver-Julesburg basin. Figure A6 illustrates an example of the density of gas wells in Weld County Colorado. The species fingerprint of the hydrocarbons observed in the air confirmed that the principal source was fossil natural gas.

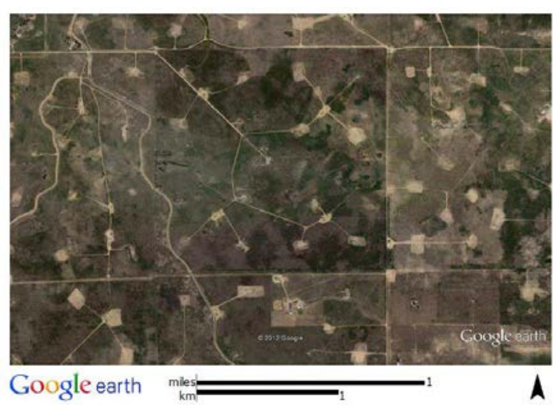


Figure A6 - Tight Gas field in Weld Co., Col.

It was estimated by NOAA that the observed natural gas concentrations in air would correspond to about 4% (2% to 7%) of the natural gas product from the area. That factor (which is disputed by the gas industry) is about twice the expected emissions of natural gas from well documented and monitored sources. Although Pétron (2012) suggests that the discrepancy is due to inaccurate monitoring of the recorded sources, another speculative explanation could be that underground migration of gas might account for some of the additional methane observed. In the reference case the combined emissions of methane are flow back (0.38%) + wellsite (0.52%) + liquid unloading (0.10%) + gas processing (0.19%) + transmission (0.52%) = 1.71% of average produced gas per well. Assuming an average of 5000 m3/day for fracked wells, as determined in Table A3, and 79% methane content in natural gas, the 1.7% quantified emissions would amount to 68 Nm^3/day/well of methane discharged to atmosphere. These figures suggest that the balance of the observed 2% to 7% of produced methane, which is unexplained, could be in the region of 12 to 210 Nm^3/day/well.

An alternative means of estimating the scale of potential methane discharges to air is to consider emission from buried waste in a municipal landfill, which is typically in the region of 10 - 100 grams of methane per square metre per day. This benchmark suggests that a gas emission rate of 100 grams CH_4 (0.14 Nm^3) per square metre per day would typically be free from environmental or safety concerns. Hence methane leaks from gas wells of that magnitude would be unlikely to necessitate remedial measures. Natural gas migrating from an imperfectly completed gas well would typically migrate through cracks and fissures in the bedrock up the well either via the annulus between the inner and outer casings or between the outer casing and the drilled hole. However, above the bedrock the migrated gas would spread through surface layers to escape to air through the ground surrounding the gas well. For 100 Nm^3/day/well to seep from the ground at the same rate as typical landfill gas would imply average seepage from an area 15 metres radius around the wellhead. Although actual leakages are from distributed points, such average seepage seems credible and would be insufficient to trigger a requirement for remedial measures in the context of a landfill.

Loizzo (2012) suggests that losses amounting to 2 to 5 tonnes of gas per year (10-20 Nm^3/day/well : average 15 Nm^3/day/well) are commonplace and are well below the level that would be detected in the normal course of operations, and would therefore would not trigger remedial action. Loizzo also suggest that leaks to the atmosphere less than 100 tonnes/year (380 Nm^3/day/well) are not obvious and are unlikely to be detected without a mandated soil gas sampling regime, so a leakage rate of 100 tonnes/year is credible as a leakage rate that would not be detected and would not cause local concern. However, there is no hard evidence (other than the speculative interpretation of the Pétron (2012) observations above) that such a rate of methane migration actually occurs, so half of that value, i.e. 50 tonnes/year (200 Nm^3/day/well) is adopted as an upper bound.

The USEPA (2012) methane emission inventory includes emission factors for fugitive methane emissions. For 3 US regions the USEPA (2012) emission factors are around 8 scf/day/well (0.23

Nm^3/day/well), whereas for the other 3 regions the fugitive emissions factors are around 40 scf/day/well (1.2 Nm^3/day/well) There is an anomaly in the USEPA data between the average from all wells and the average from wells that leak. Leakage of 1 Nm^3/day/well is assumed from this data to be a lower bound of the scale of leakage from wells that leak. Based on the foregoing discussion, methane migration from natural gas wells that leak is assumed to be 15 Nm^3/day/well within the wide range of 1 to 200 Nm^3/day/well.

A9.3 Combined assessment of methane migration factors

The foregoing quantified discussion has identified wide ranges of uncertainty associated with the fraction of wells from which methane might migrate and also associated with the amount of natural gas that might be released to air. The two factors are compounded to give a composite methane migration factor and range as shown in Table A4 using the uncertainty combination methodology described in Section 2.

This attempt to quantify the likelihood of methane migration to air from operating gas wells has determined a value of 3 Nm^3/well/day within the range 0.3 to 30 Nm^3/well/day.

Table A4 Composite methane migration factors

	Minimum	Mean	Maximum
Estimated fraction of wells with gas migration leakage	6%	20%	30%
Estimated gas migration leakage per well that leaks (Nm^3/day/well)	1	15	200
Average methane migration factor (Nm^3/day/well)	0.3	3	30

Assessment of lifetime fugitive emission of migrating gas is based on the assumption that emissions will continue during gas production and will cease when the well is sealed at the end of its productive life. This modelling assumption is consistent with the assumption that reworking of an old well with a hydraulic fracturing operation is equivalent to the creation of a new well. However, complete sealing of a slowly leaking well after all production activity has ceased is unlikely to occur if there is no local environmental or safety reason to do so and no source of income to fund remediation; unless monitoring of effective sealing of abandoned wells is a contingent liability on the well operators that is enforced.

Other studies aimed at quantifying methane emissions associated with gas production, (e.g. Howarth (2011), USEPA (2012), and API/ANGA (2012)) generally do not consider methane migration and discharge external to the well. As discussed above, there is no reliable data to provide a basis for a quantified estimation method. The matter of gas migration due to loss of well integrity and discharge external to the well is discussed in AEA (2012) and notes *"However, this issue is not specific to unconventional gas and such emission need to be* *prevented for water protection and healthy and safety reasons."* AEA 2012 also attributes historical data of gas migration to wells that predate current well design and abandonment processes.

A10. Volume of Fracking Fluid Injected per Well

The volume of fracking fluid injected per well depends on many factors and varies widely. A typical hydraulic fracturing operation is reported to require about 4 to 7 million US gallons, corresponding to 15.500 to 26,500 cubic metres. Accordingly it is assumed that the average water consumption of 20,000 cubic metres per fracked well within the range +/-50%. The AEA default value is 18,184 m^3 of water used per fracked well.

Volume of fracking fluid required to prepare a shale well	Minimum	Mean	Maximum
	10,000 m^3	20,000 m^3	30,000 m^3

A11. Fraction of Fracking Fluid Flowing Back

After hydraulic fracturing of a new gas well is completed the well has to be dewatered to allow gas to be produced. Since the volume of a completed well (vertical + lateral) is about 40 cubic meters all of the injected water will be within the formation. It is reported that about 30% of the injected fracking fluid is typically produced as flowback fluid in the well completion process. That fraction varies widely. Accordingly it is assumed that the average fraction of injected fluid flowing back is 30% within the range +/-50%.

Fraction of fracking fluid flowing back during completion of a shale well	Minimum	Mean	Maximum
	15%	30%	45%

A12. Days of Fluid Flowback during Well Completion

The flowback of fluid takes several days to dewater a well and continues until the gas is flowing freely at the Initial Production Rate (IPR), as described above. Early descriptions of the hydraulic fracturing process suggested that fluid flowback typically takes 10 days. Recent industry claims are that a fractured well can be dewatered in three days, but no justification for that claim has been obtained. The number of days of fluid flowback is assumed to be 7 within the range of 3.5 to 14 days.

Number of days of fluid flowing back during completion of a shale well	Minimum	Mean	Maximum
	3	7	10

Fluid flowback initially produces just liquid from the well. This develops into a two phase flow with progressively decreasing liquid fraction until eventually just gas is being produced. Industry sources indicate that the flow of gas during the flow back period increases linearly up to the IPR. On this basis, for the assessment model, the total amount of gas produced during the liquid flowback period is assumed to be half of the IPR multiplied by the number of days of fluid flowback.

A13. Probability of Reduced Emission Completion

The natural gas industry has developed a procedure called Reduced Emission Completion (REC) or Green Completion. This involves capturing the gas produced with flow back fluid, either for flaring or for dispatch as product. The REC procedure is complex and costly and is unlikely to be self-financing from the additional gas produced for sale. However, there is currently a push by the USEPA to require REC equipment to be installed as standard practice. There is resistance by the US gas industry to the imposition of such a mandatory regulation.

In view of these considerations the default fraction of wells where REC is installed is assumed to be 25% within the range of 5% to 50%.

Fraction of shale gas well completions with REC technology	Minimum	Mean	Maximum
	5%	25%	50%

In a remote location without a regulatory requirement to install REC equipment the gas associated with flowback fluid would normally gas be vented to atmosphere and REC technology would only be installed in cases where there was a safety imperative.

This is the basis for the contentious USEPA emission factor for gas emissions with flow back fluid of 9,175 Mscf (260,000 m^3). Recent US industry claims are that this factor is 10 times too high. The above default assumptions of 20,000 m^3/day IPR and 7 days fluid flowback duration would correspond to 70,000 m^3 of gas release, which is intermediate between the USEPA and US gas industry values.

A14. Efficiency of Reduced Emission Completion

Reduced Emission Completion involves separation of the two phase flow produced from the gas well, which will be less than perfect separation. Also, the water is supersaturated with methane due to the high down-hole pressure, so some of that dissolved methane will effervesce from the flow back fluid in the storage pond after separation. Therefore REC processes will not capture all the methane produced. It is assumed that REC is constant at 90% efficient.

A15. Liquid Unloading

Additional venting of gas occurs during “liquid unloading” to remove accumulated water from a gas well, which is blocking the flow of gas. The traditional method of liquid unloading is to close off the well, allow the pressure to build up in the well and then open the well to atmosphere so that a quantity of gas flows rapidly up the well and blows out the water. This produces a lot of natural gas with removed water and may be required many times per year in wells where water intrusion accumulates.

Some wells are suited to the use of plunger lifts in which a close fitting plunger is dropped down the well and then brought back up again by the gas carrying a slug of water. The regular deployment of such devices can reduce the gas loss due to liquid unloading.

Wells requiring liquid unloading tend to be wells with lower than average output because a high velocity gas flow can more easily carry water vapour out of the well during normal production. Where water intrusion is minor the water can be carried out of the well as a saturated vapour fraction in the gas and liquid unloading is not required.

The USEPA greenhouse gas inventory for 2010(USEPA 2012) reports that more than half of all the gross methane emissions from gas production arise from the periodic unloading of liquid (water) from some wells. This assessment is disputed by the gas industry in API/ANGA (2012).

Conventional wells frequently require liquid-unloading as they mature in order to mitigate water intrusion as the reservoir pressure drops. However, it was previously generally asserted by the gas industry that liquid unloading was not applicable to unconventional gas produced from deep wells. That assertion was adopted in early analyses.

The API/ANGA (2012) summary and analysis of the survey of data on operating wells reports extensive liquid unloading from unconventional wells with and without plunger lifts. This data source indicates that the need for liquid unloading of unconventional wells is at least as extensive as from conventional wells. Analysis of the data in the API/ANGA (2012) report indicates that the generally lower gas flowrates from unconventional wells in that report could possibly imply that liquid unloading emissions from unconventional wells represented a larger fraction of gas production than from conventional wells.

A16. Probability that Gas Wells require Liquid Unloading

The USEPA (2012) data for 2010 indicates a weighted average methane emission factor of 1,317 Mscf gross emissions per year for wells that requires liquid unloading and that such wells comprise about 37% of all US gas wells; being 179,391 wells out of the 484,795 non-associated gas wells in the USA in the 2010 inventory. In contrast, the API survey (API/ANGA 2012) determines that 65,669 such wells only comprise 13.5% of all US gas wells.

This proportion is highly dependent on geological conditions and features of the design of the well. There is insufficient data available to distinguish between conventional and unconventional gas wells. For the purpose of this assessment it is assumed that 25% +/-50% of wells require liquid unloading

.**Fraction of all wells that require liquid unloading**	Minimum	Mean	Maximum
	12.5%	25%	37.5%

A17. Probability that Liquid Unloading Associated Gas is Vented

As with dewatering of wells during completion, there are technologies available for reducing the amount of gas that is vented during liquid unloading operations. Since liquid unloading is carried out frequently during production, there is a greater economic incentive to avoid gas losses than in the case of a one-off fracturing fluid flowback event. The API/ANGA (2012) report provides data indicating that 36% of gas produced during liquid unloading events is vented. For the purpose of this assessment it is assumed that 36% +/-50% of gas released during liquid unloading is vented.

Fraction of liquid unloading gas that is vented	Minimum	Mean	Maximum
	18%	36%	54%

Both the EPA and API methodologies are based on the greenhouse gas accounting equation W-8 (see discussion below concerning wells with plunger lifts and equation W-9) from 40 CRF 98 subpart W, which is detailed in the API report (API 2012b).

This equation relates to wells that require liquid unloading and do not have plunger lifts.

$$E = 0.00037 * V * CD^2 * WD * SP + SFR * (HR-1)$$

Where:-

E = Annual average natural gas emissions in standard cubic feet per year

V = average number of venting events per well per year

CD = Well internal casing diameter in inches

WD = Well depth in feet

SP = Well Shut-in pressure in psia

SFR = Average flow line rate in standard cubic feet per hour

HR = Hours that the well is left open to atmosphere during liquid unloading

Table A4 shows values for these parameters used in the EPA and API assessments. The API values are the weighted average values of these parameters for the subset of wells in the API survey, which do not have plunger lifts. These parameters are extracted from the API report (API/ANGA 2012). The data presented in Table A5 includes back-calculation of the effective production flowrates corresponding to the significantly different emission rates determined by using the EPA and the API parameters.

Table A5. - Liquid unloading emission calculations on single well basis (metric units)

	Units	EPA	API non-plunger data weighted ave
V = venting events per year	per well	38.7	32.6
CD = Casing diameter	millimetres	127	116
WD = Well depth	metres	1829	1656
SP = Well shut in pressure	Bar abs.	7.8	8.8
SFR = Production flowrate	m^3/d	12,516*	3,511*
HR = time open to atmosphere	hours	3.0	1.9
Methane content in gas	Vol %	78.8%	78.8%
E = Calculated emissions	‘000m^3CH_4/yr	37.3	7.2
Emissions/Production	%	1.04%	0.71%

* Effective production flowrate back-calculated from emissions

Figure A7. Relationship between well productivity and liquid unloading emissions

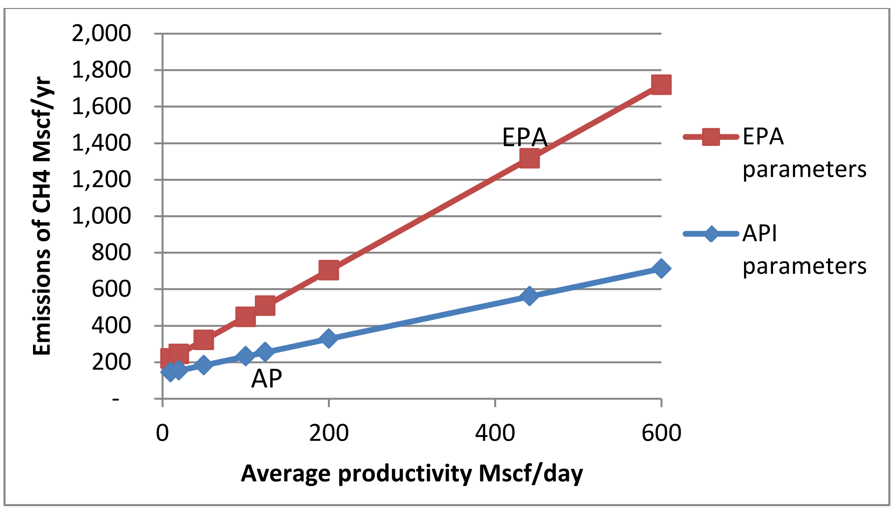


Figure A7 shows the relationship between the emissions of methane and the gas well productivity using the EPA and API parameters listed in Table A5. This shows the effect of the second term in the equation, which is the product of productivity and the duration of venting. The steeper line for the EPA parameters is due to the venting duration being assumed to be 3 hours compared with 1.9 hours reported from the API data survey.

A18. Liquid Unloading events per year

For wells that require liquid unloading the API/ANGA (2012) survey reports and average of 33 liquid unloading events per year for shale gas well and 37 events per year on average for conventional gas wells. Since there is no significant difference, the default number of liquid unloading events per year is assumed to be 35 with a +/-50% variance.

Number of liquid unloading events per year	Minimum	Mean	Maximum
	17	35	51

A19. Liquid Unloading Duration

The liquid unloading operation comprises two stages, as illustrated in the above equation; firstly displacing the gas from the well that is above the water layer and secondly additional gas venting after bulk water displacement to dry the well. The "H-1" term in the above equation accounts for the second stage of liquid unloading , based on the assumption that the duration of the first stage is one hour. Analysis of the data in the API/ANGA(2012) survey indicates that the duration of liquid unloading averages 1.9 hours within the range 0.5 hours to 3 hours.

Duration of a liquid unloading event	Minimum	Mean	Maximum
Hours	0.5	1.9	3

A20. Well Site Surface Plant Methane Leaks and Losses

Figure A8 presents data from the USEPA (2012) inventory, which shows that that the methane emission from well sites is dominated by pneumatic controllers, which use the raw gas as their working fluid. These controllers lose a small fraction of the working fluid in their normal operation. The use of modern electronic controllers powered by solar cells would reduce this source of methane emission.

The USEPA greenhouse gas inventory reports that the total fugitive emissions from the sources shown in Figure A8 is 0.52% of the gas produced. For the purpose of this assessment it is assumed that 0.52% +/-50% of produced gas is lost as well site fugitive emissions.

Well site fugitive emissions	Minimum	Mean	Maximum
Fraction of produced gas	0.26%	0.52%	0.77%

Figure A8 Methane Emissions from Well Sites

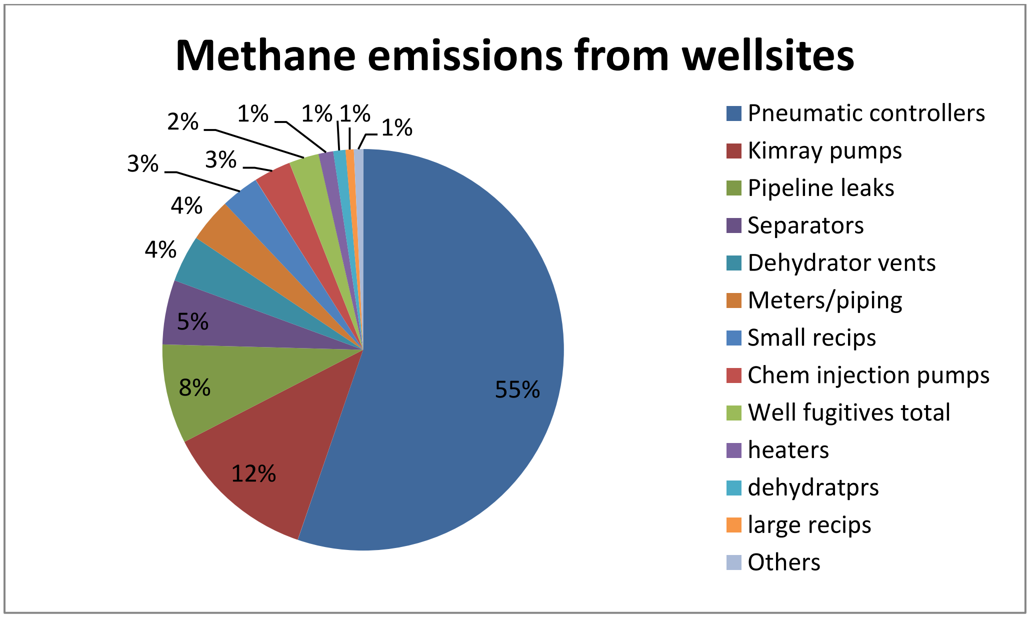
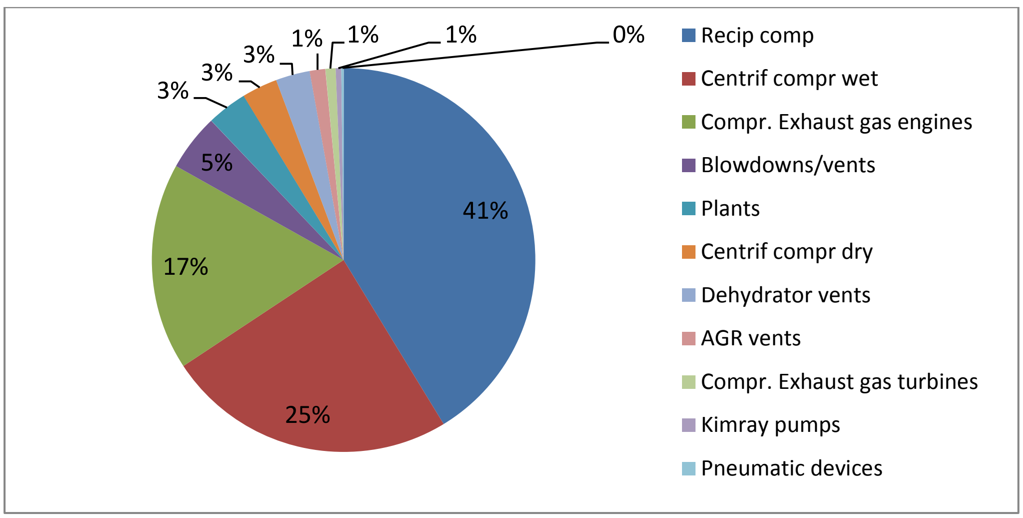


Figure A9 Methane Emissions from Gas Processing



A21. Gas Processing Plant Methane Leaks and Losses

Figure A9 shows that the methane emission from processing plants are dominated by leaks from seals in gas compressors.

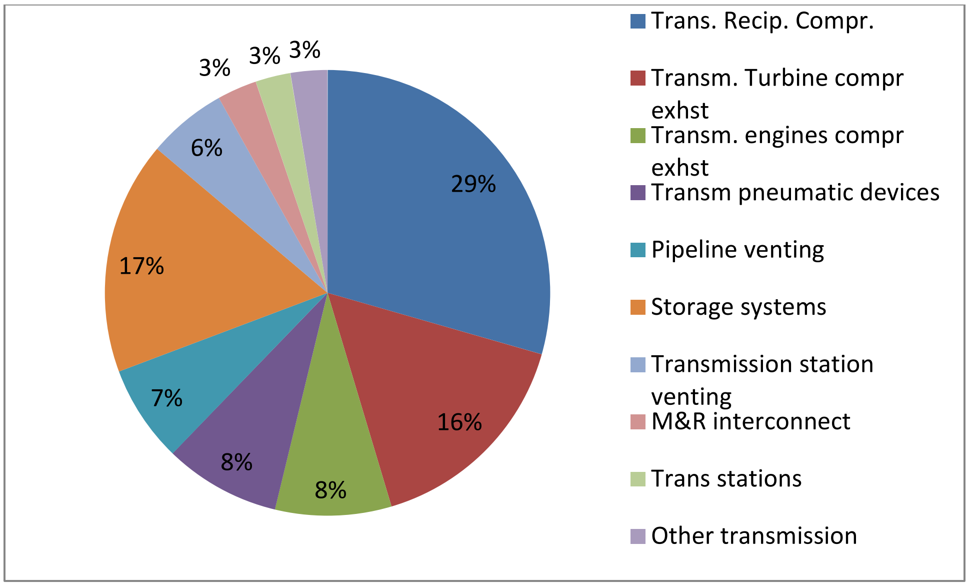
The USEPA greenhouse gas inventory reports that the total fugitive emissions from the sources shown in Figure A9 is 0.19% of the gas processed. For the purpose of this assessment it is assumed that 0.19% +/-50% of produced gas is lost as well site fugitive emissions.

Gas processing fugitive emissions	Minimum	Mean	Maximum
Fraction of produced gas	0.10%	0.19%	0.29%

A22. Transmission and Storage Methane Leaks and Losses

Figure A10 shows that the methane emission from gas transmission is dominated by leaks from seals in gas compressors.

Figure A10 Methane Emissions from Gas Transmission



The USEPA greenhouse gas inventory reports that the total fugitive emissions from the sources shown in Figure A10 is 0.52% of the gas processed. For the purpose of this assessment it is assumed that 0.52% +/-50% of produced gas is lost as well site fugitive emissions.

Gas transmission fugitive emissions	Minimum	Mean	Maximum
Fraction of produced gas	0.26%	0.52%	0.76%

A23. Drilling Diesel Consumption

The amount of diesel fuel consumed by a drilling rig is variously reported to be in the region of 150 US gallons per day for drilling 250 ft of well. That corresponds to 7.5 litres per metre of well drilled. . For the purpose of this assessment it is assumed that 7.5 litres of diesel +/-50% is used per metre of well drilled.

Drilling diesel consumption	Minimum	Mean	Maximum
Litres per metre of well drilled	5.3	7.5	9.8

A24. Hydraulic Fracturing Pumping Diesel Consumption

A fleet of truck-mounted high pressure pumps are required to carry out a hydraulic fracturing operation. For a typical 5 million US gallon (20,000 m^3) fracking operation 8000 BHP (6MW) of pumping capacity might be required. Assuming those pumps run at an average of 50% of full load, the diesel fuel consumption would be about 1,000 litres per hour. If the fracking operation takes 6 days the total diesel consumption would be 144,000 litres, corresponding to 7.2 litres per cubic metre of fracking fluid delivered. For the purpose of this assessment it is assumed that 7.2 litres of diesel +/-50% is used per cubic metre of fracking fluid used.

Drilling diesel consumption	Minimum	Mean	Maximum
Litres per m^3 of fracking fluid	3.6	7.2	10.8

A25. Own Use of Gas in Compressors - Well Site

The USEPA (2012) GHG inventory reports as an activity factor the consumption of 91 billion HPhr of gas compression with reciprocating engines at gas well sites in the US in 2009. Assuming 30% engine efficiency, the raw gas consumed by those compressors would amount to 816 PJ. The USEIA (2012) reports the production of 26.1 Tcf (31.4 TJ) of raw gas in 2009. Therefore the own use of natural gas by well site compressors is estimate to be 2.59% of the gas produced. For the purpose of this assessment it is assumed that 2.59% +/-25% of produced gas is consumed by gas gathering compressors at the well site.

Own use of gas at well site	Minimum	Mean	Maximum
Fraction of gas produced	1.94%	2.59%	3.24%

A26. CO_2 from Acid Gas Removal

Table A6 shows that the volumetric CO_2 content of natural gas might be reduced from 3.5 % to 1.8% when raw gas is processed to pipeline specification. Thus the CO_2 discharged from the gas processing plant might be 1.7% of the processed gas. The CO_2 contents of natural gases can vary widely. For the purpose of this assessment it is assumed that the CO_2 content of natural gas is reduced by 1.7% of the processed gas volume with the range of 0% to 10%.

CO_2 content reduction	Minimum	Mean	Maximum
Volume fraction of gas processed	0%	1.7%	10%

A27. Own Use of Gas in Compressors - Processing

The USEPA (2012) GHG inventory reports as an activity factor the consumption of 79 billion HPhr of gas compression with reciprocating engines and gas turbines in gas processing operations in the US in 2009. Assuming 30% engine efficiency for reciprocating engines and

35% efficiency for gas turbines driven compressors, the raw gas consumed by those compressors would amount to 655 PJ. The USEIA (2012) reports the production of 21.6 Tcf (26.1 TJ) of processed gas in 2009. Therefore the own use of natural gas by gas processing compressors is estimated to be 2.51% of the gas processed. For the purpose of this assessment it is assumed that 2.51% +/-25% of processed gas is consumed by gas compressors in the processing stage.

Own use of gas in gas processing	Minimum	Mean	Maximum
Fraction of gas processed	1.88%	2.51%	3.14%

A28. Own Use of Gas in Compressors - Transmission

The USEPA (2012) GHG inventory reports as an activity factor the consumption of 69 billion HPhr of gas compression with reciprocating engines and gas turbines in gas transmission operations in the US in 2009. Assuming 30% engine efficiency for reciprocating engines and 35% efficiency for gas turbines driven compressors, the raw gas consumed by those compressors would amount to 605 PJ. The USEIA (2012) reports the delivery of 20.6 Tcf (23.7 TJ) of raw gas in 2009. Therefore the own use of natural gas by gas transmission compressors is estimate to be 2.55% of the gas delivered. For the purpose of this assessment it is assumed that 2.55% +/-25% of processed gas is consumed by gas compressors in the processing stage.

Own use of gas in gas transmission	Minimum	Mean	Maximum
Fraction of gas delivered	1.91%	2.55%	3.19%

A29. Own Use of Gas by LNG technology

Liquefied natural gas (LNG) technology involves cooling natural gas to below the boiling point of methane (-161.6^{o}C) so that the gas can be transported as a liquid at ambient pressure in highly insulated containers (usually spherical). After receipt at the destination the LNG is reheated to regasify it for pipeline distribution. The inclusion of LNG technology in the distribution train for natural gas involves own use of gas in three stages; liquefaction, transport and regasification.

Liquefaction of natural gas is a cascading cryogenic process, which also results in the separation of higher hydrocarbons. The design thermal efficiency of the liquefaction process, based on the use of gas turbines is reported (Conoco 2007) to be about 92% in the range 89% to 93%. In addition electricity would be required for associated operations including product vapour recovery and feed pre-treatment. If generated on site from gas that additional duty might reduce those efficiency values by one percentage point. For the purpose of this assessment it is assumed that an LNG production facility would typically involve the loss of 9% of the feed gas within the range 8% to 12%.

LNG is transported internationally on large vessels with four or five large insulated spheres. A typical tanker might carry 3.3 PJ of LNG. For optimum fuel economy (fuel consumption increases exponentially with speed) an LNG tanker might travel at 35 km per hour. International LNG transport routes might range from 4 days to 12 days. There is constant boil off of gas from the LNG tanks. That boil off can be re-liquefied and returned to the LNG tanks. However, it is more greenhouse efficient to use the boil-off gas to power the ship. A ship of the size of an LNG tanker travelling at 35 kph might consume 90 tonnes/day (3800 GJ/day) of fuel oil equivalent, and perhaps half that amount for the empty return trip. On this basis, delivery of LNG might typically consume 0.7% to 2.1% of the pay load.

The energy required to regasify LNG for distribution in a pipeline is about 1.65% of the energy content of methane. In some applications seawater might be used as most of the energy source, but for this generic assessment it is assumed that boil-off gas would normally used to provide the regasification energy.

If LNG technology is used in the energy supply chain then the losses of gas described above would compound the greenhouse gas emissions occurring earlier in the gas supply chain. Table A6 shows the development of factors for the impact of LNG on the precombustion emissions of natural gas used in this assessment.

Table A6 Own use of gas for LNG system

Own use of gas in LNG transportation of natural gas	Minimum	Mean	Maximum
Own use for liquefaction as LNG	8%	9%	12%
Distance shipped as LNG - km	3,500	7,000	10,000
Own use for LNG regasification	0.2%	1.65%	1.65%
Overall own use by LNG system	9.7%	11.8%	13.7%

A30. Relative gas flows: Gross Production, Gas Processed and Gas Delivered

Emissions of methane from the well site are generally proportional to the gross production of gas from the well. However, the quantity of gas dispatched by pipeline to the central gas processing facility is significantly less than the gross gas produced up the well. USEIA (2012) data shows that on average for the years 2005 to 2010 in the USA the gas marketed was 82.3% (within the range 80.7% to 83.5%) of the gas produced;. Of the gas that was not dispatched from the wells, 14.2% (within the range 12.8% to 15.8%) was re-injected into gas wells. The balance of non-dispatched gas ties up reasonably with estimates of 2.5% own use and around 1% combined fugitive losses.

There are additional gas losses and own use in processing and transmission. The same USEIA (2012) data indicates that delivered gas is 95.3% (within the range 95.2% to 95.5%). The 4.7%

losses are distributed approximately as 2% consumption in gas processing, 2% transmission losses and around 0.7% fugitive losses.

When natural gas is reticulated at low pressure to domestic, commercial and small industrial consumers there are significant additional distribution losses. However, power generation plants generally take their bulk gas supply directly from the high pressure transmission network, so low pressure gas distribution system losses are not taken into account in this assessment of pre-combustion greenhouse gas emissions associated with gas fired power generation.

The factors assumed in the model to compound precombustion losses are as follows:-

Gas flow ratios	Minimum	Mean	Maximum
Gas delivered / Gas processed	95.2%	95.35%	95.5%
Gas delivered / Gas produced	80.7%	82.3%	83.580%

A31. Methane / Energy Ratio

The ratio of the methane content of natural gas to its energy content is need to determine the greenhouse equivalent emissions of fugitive gas on the basis of the loss of fuel. This ratio depends on the gas composition which differs between raw gas and processed pipeline gas.

Table A7 shows the assumed gas compositions of raw gas and pipeline gas and the corresponding methane to energy ratios.

Actual gas compositions vary. For assessment of uncertainty, it is assumed that these methane to energy ratios can vary by up to 10%.

Table A7 – Gas properties

Assumed gas properties	**Raw gas**	**Processed pipeline gas**
Gas composition		(excluding LNG stage)
Methane	78.8%	83.9%
Ethane	8.6%	9.2%
Higher hydrocarbons	8.7%	4.7%
CO_2	3.5%	1.8%
Nitrogen	0.4%	0.4%
MJ-lhv / Nm^3	42.84	40.85
Kg CO_2 / GJ-lhv from burned gas	59.512	57.945
Kg CH_4 / GJ-lhv in fugitive gas	11.936	13.303
Energy density Mscf/GJ-lhv	0.8286	0.8690

A32. Coal Mining Methane Emissions

The USEPA inventory details net methane emissions from coal mining in the USA after any utilisation or flaring. The derived emission factors for 2010 data are 0.3005 kg.CH_4/GJ-lhv for coal from underground mines and 0.0424 kg.CH_4/GJ-lhv for coal from opencast mines.

A life cycle analysis by Jaramillo (2007) based on US 1997 data gave similar emission factors of 0.266 kg.CH_4/GJ-lhv for coal from underground mines and 0.040 kg.CH_4/GJ-lhv for coal from opencast mines.

For the purpose of this assessment default values of 0.3 and 0.04 kg.CH_4/GJ-lhv are assumed for underground and opencast mining respectively within a range of +/- 10%.

Coal mine methane emissions kg.CH_4/GJ-lhv	Minimum	Mean	Maximum
Underground coal mining	0.270	0.300	0.330
Opencast coal mining	0.036	0.040	0.044

A33. Fraction of Coal Mined Opencast

The USEPA and USEIA data sources report that in the USA about 2/3 of coal is produced in open cast surface mines and only one third from underground mines. In Australia about 80% of coal is opencast. In contrast coal mining in China is dominated by underground mining with open cast mining being relatively unusual. For the purpose of this assessment it is assumed that a default of 50% of coal on an energy basis is opencast within the range 10% to 90%.

Fraction of coal opencast	Minimum	Mean	Maximum
Energy basis	10%	50%	90%

A34. Coal Mining and Transport CO_2

The life cycle analysis by Jaramillo (2007) based on US 1997 data compiled emission factors for fuel use and for coal transport. Table A8 shows the contributions of energy sources and modes of transport to the coal mining and transport CO_2 emission factors.

Table A8 – Coal mining and transport CO_2 emission factors

$kg.CO_2/GJ$-lhv	**Underground mining**	**Opencast mining**
Light distillate oil	0.027	0.239
Heavy residual oil	0.007	0.028
Gasoline	0.003	0.020
Natural gas	0.003	0.045
Electricity	0.443	2.059
Total mining	0.483	2.392
Rail	1.363	
Barge	0.010	
Truck	0.006	
Total transport	1.380	
Total mining and transport	1.86	3.77

The CO_2 emissions from coal transport are based on transport distances of 796, 337 and 38 miles by rail, barge and truck respectively in the US context.

For the purpose of this assessment it is assumed that default CO_2 emission factors for coal mining and transport are 1.9 and 3.8 $kg.CO_2/GJ$-lhv +/-25% for underground and opencast mining respectively.

Coal mining and transport energy use	Minimum	Mean	Maximum
Underground ($kg.CO_2/GJ$-lhv)	1.43	1.9	2.38
Opencast ($kg.CO_2/GJ$-lhv)	2.85	3.8	4.75

A35. Geothermal Gradient

The geothermal gradient is used in the model to estimate the down-hole solubility of methane in fracking fluid. A typical geothermal gradient is $24^oC/km$, with significant variance. For the purpose of this assessment it is assumed that the default geothermal gradient is $24^oC/km$ +/-50%.

Geothermal Gradient	Minimum	Mean	Maximum
Deg C per km	12	24	36

A36. Ambient Temperature

The ambient temperature is used in the model to estimate the surface solubility of methane in flow-back fluid. For the purpose of this assessment it is assumed that the default ambient temperature is 15^{o}C +/- 15^{o}C.

Ambient temperature	Minimum	Mean	Maximum
Deg C	0	15	30

APPENDIX B

DATA FOR FIGURES 2 and 5 to 7

Table B1. - Data for Figure 2

Kg.CO_2-eq / MWhe	**Shale gas default case**	**Shale gas 90% CO_2 capture**	**Conv. gas default case**	**Conv. gas 90% CO_2 capture**	**Coal default case**	**Coal with 90% CO_2 capture**
Methane emissions (as CO_{2+}equivalent)						
Fugitives attributable to migration	1.5	1.7	2.5	2.9	0.0	0.0
Well site vents and losses	24.6	28.7	15.1	17.6	0.0	0.0
Processing and transmission losses	16.0	18.7	16.0	18.7	0.0	0.0
Coal mining methane emission	0.0	0.0	0.0	0.0	36.8	46.2
CO_2 emissions						
Gas well drilling and pumping diesel	3.3	3.9	0.1	0.1	0.0	0.0
Well site equipment	12.7	14.8	12.7	14.8	0.0	0.0
Gas processing and CO_2 stripping	12.5	14.6	12.5	14.6	0.0	0.0
Gas transmission (including LNG)	10.0	11.7	10.0	11.7	0.0	0.0
Coal mining and transport diesel	0.0	0.0	0.0	0.0	23.3	29.3
Total precombustion emissions	80.7	94.1	68.9	80.3	60.1	75.5
Combustion emissions	375	44	375	44	753	95
Total FFC GHG emissions	456	138	444	124	814	170

Table B2. - Data for Figure 5

Kg.CO_2-eq / MWhe	Shale gas default case GWP=25	Shale gas GWP=72	Shale gas GWP=105	Coal default case GWP=25	Coal GWP=72	Coal GWP=105
Methane emissions (as CO_2-equivalent)						
Fugitives attributable to migration	1.5	4.3	6.2	0.0	0.0	0.0
Well site vents and losses	24.6	70.8	103.3	0.0	0.0	0.0
Processing and transmission losses	16.0	46.2	67.3	0.0	0.0	0.0
Coal mining methane emission	0.0	0.0	0.0	36.8	106.0	154.6
CO_2 emissions						
Gas well drilling and pumping diesel	3.3	3.3	3.3	0.0	0.0	0.0
Well site equipment	12.7	12.7	12.7	0.0	0.0	0.0
Gas processing and CO_2 stripping	12.5	12.5	12.5	0.0	0.0	0.0
Gas transmission (including LNG)	10.0	10.0	10.0	0.0	0.0	0.0
Coal mining and transport diesel	0.0	0.0	0.0	23.3	23.3	23.3
Total precombustion emissions	80.7	159.9	215.5	60.1	129.4	178.0
Combustion emissions	375	375	375	753	753	753
Total FFC GHG emissions	456	535	591	814	883	931

Table B3. - Data for Figure 6

Kg.CO_2-eq / MWhe	Shale gas default case	Shale gas with LNG	Conv. gas default case	Conv. gas with LNG	Natuna gas	Coal default case
Methane emissions (as CO_2-equivalent)						
Fugitives attributable to migration	1.5	1.6	2.5	2.7	2.5	0.0
Well site vents and losses	24.6	27.0	15.1	16.6	15.1	0.0
Processing and transmission losses	16.0	17.6	16.0	17.6	16.0	0.0
Coal mining methane emission	0.0	0.0	0.0	0.0	0.0	36.8
CO_2 emissions						
Gas well drilling and pumping diesel	3.3	3.7	0.1	0.1	0.1	0.0
Well site equipment	12.7	14.0	12.7	14.0	12.7	0.0
Gas processing and CO_2 stripping	12.5	13.8	12.5	13.8	382.1	0.0
Gas transmission (including LNG)	10.0	62.0	10.0	62.0	10.0	0.0
Coal mining and transport diesel	0.0	0.0	0.0	0.0	0.0	23.3
Total precombustion emissions	80.7	139.7	68.9	126.7	438.6	60.1
Combustion emissions	375	375	375	375	375	753
Total FFC GHG emissions	456	515	444	502	814	814

Table B4. - Data for Figure 7

Kg.CO_2-eq / MWhe	Shale gas default case	Shale gas + LNG + GWP=105	Shale gas + LNG + GWP=105 + Migration=4%	Conv. gas + LNG + GWP=105	Conv. gas + LNG + GWP=105+ Migration=3%	Coal with GWP=105
Methane emissions (as CO_2-equivalent)						
Fugitives attributable to migration	1.5	6.9	274.9	11.3	322.3	0.0
Well site vents and losses	24.6	113.5	113.5	69.7	69.7	0.0
Processing and transmission losses	16.0	74.0	74.0	74.0	74.0	0.0
Coal mining methane emission	0.0	0.0	0.0	0.0	0.0	154.6
CO_2 emissions						
Gas well drilling and pumping diesel	3.3	3.7	3.7	0.1	0.1	0.0
Well site equipment	12.7	14.0	14.0	14.0	14.0	0.0
Gas processing and CO_2 stripping	12.5	13.8	13.8	13.8	13.8	0.0
Gas transmission (including LNG)	10.0	62.0	62.0	62.0	62.0	0.0
Coal mining and transport diesel	0.0	0.0	0.0	0.0	0.0	23.3
Total precombustion emissions	80.7	287.8	555.8	244.8	555.8	178.0
Combustion emissions	375	375	375	375	375	753
Total FFC GHG emissions	456	663	931	620	931	931