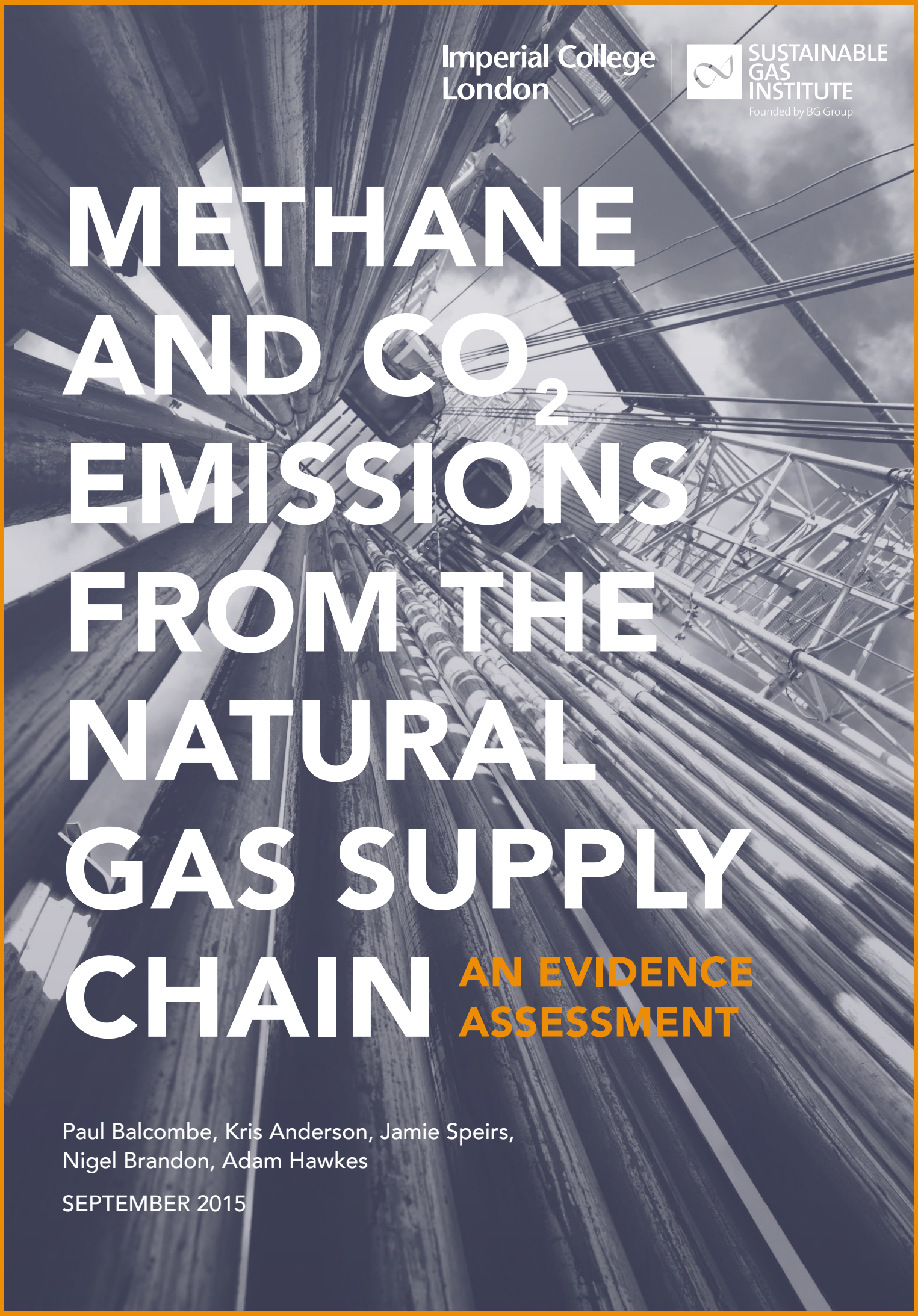

Imperial College London

SUSTAINABLE GAS INSTITUTE
Founded by BG Group

METHANE AND CO_2 EMISSIONS FROM THE NATURAL GAS SUPPLY CHAIN

AN EVIDENCE ASSESSMENT

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SEPTEMBER 2015

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Preface

Launched in May 2014 by Imperial College London and BG Group, the Sustainable Gas Institute (SGI) aims to lead research and define innovative technologies that enable natural gas to play a key role in a low carbon world. The hub of the Institute is situated at Imperial College London and performs overarching research in energy systems modelling and addresses contentious issues in natural gas sustainability through evidence based reviews, or White Papers, aimed at academia, industry and policy makers alike. The hub works with centres of excellence around the world to develop spoke programmes around key themes. These spoke programmes undertake technology research and interact with the hub via shared PhD and researcher training programmes in order to foster future leaders for the sector.

This report is the first of a series of White Papers from the Sustainable Gas Institute. The aim of the SGI White Paper series is to conduct systematic reviews of the evidence on topical and/or controversial issues of relevance to the role of natural gas in sustainable energy systems.

Executive summary

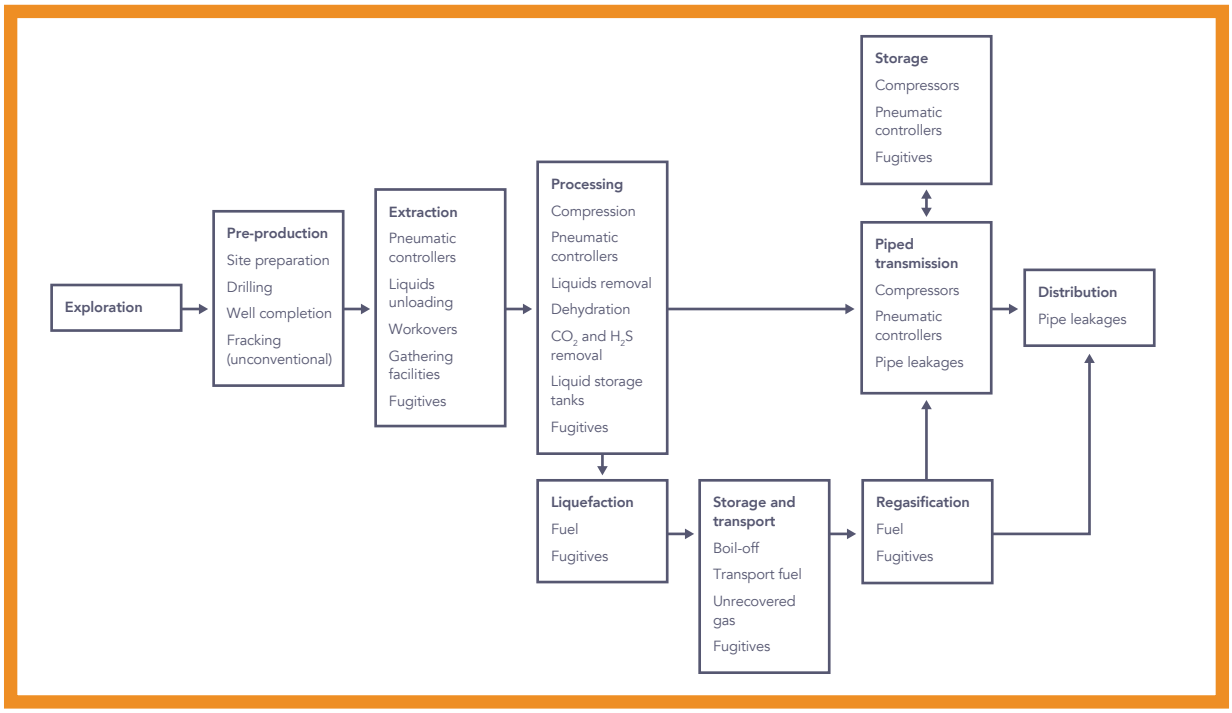
Natural gas could have an important role in future low carbon sustainable energy systems. It is less carbon intensive than coal by approximately half and a global marketplace is forming as international gas consumption has risen steadily over the last decade and looks set to increase further. The development of unconventional gas resources is spurring further interest, with the potential to contribute to lower energy system cost and increased energy system security.

Yet there is still uncertainty and debate regarding the contribution that natural gas could or should make towards meeting global climate change mitigation ambitions. Whilst natural gas may represent an improvement from coal, carbon dioxide (CO_2) emissions still may not be low enough to keep emissions within a demanding global carbon budget. Additionally, methane is a potent greenhouse gas (GHG) and quantities are released in to the atmosphere through the gas supply chain. Therefore, if methane emissions were high enough, any benefits associated with reduced end-use carbon intensity could be negated.

A number of recent studies have estimated methane emissions from the natural gas supply chain, which has resulted in a wide variation in estimates. The following are matters of particular contention:

- The magnitude and range of methane emissions across the natural gas supply chain.
- The methods, data and assumptions used to estimate these emissions.
- The 'global warming potential' of methane compared to CO_2 and the timescale over which it should be considered.

FIGURE ES-1
The natural gas supply chain
Listed within each stage are the key processes and/or emission sources. Note, emissions are listed as examples and this does not constitute a comprehensive list.
H_2S = Hydrogen Suphide



The Sustainable Gas Institute (SGI) has conducted a comprehensive review of this topic in order to inform the debate. This paper systematically reviews the body of evidence on the magnitude of methane and CO_2 emissions in the natural gas supply chain. In particular the review focusses on determining the range of emission estimates, the associated uncertainty as well as methodological differences and any gaps in the evidence where further work is needed. The boundaries of the study cover conventional and unconventional wells, and include the exploration, extraction, processing, transmission, storage and distribution of stages of the natural gas supply chain, as well as the Liquefied Natural Gas (LNG) process (described in Figure ES-1).

Key findings

1. Overall, the range of estimated greenhouse gas emissions across the supply chain is vast: between 2 and 42 g CO_2 eq./ MJ HHV (Higher Heating Value) assuming a global warming potential of 34 for methane. If the gas were to be used for electricity generation, these supply chain emissions would be equivalent to 14–302 g CO_2 eq./ kWh electricity generated. As shown in Figure ES-2, a small number of studies estimate even higher emissions from specific supply chain stages or facilities, in particular from well completions (for unconventional gas) and liquids unloading processes. The range of methane-only emission estimates is from 0.2% to 10% of produced methane, which is equivalent to 1 to 58 g CO_2 eq./ MJ HHV. The majority of estimates lie between 0.5% and 3% of produced methane, which is equivalent to 2.9 to 17 g CO_2 eq./ MJ HHV. These values represent a wide range of extraction, processing and transport routes, reservoir conditions, regional regulation and estimation methodologies.

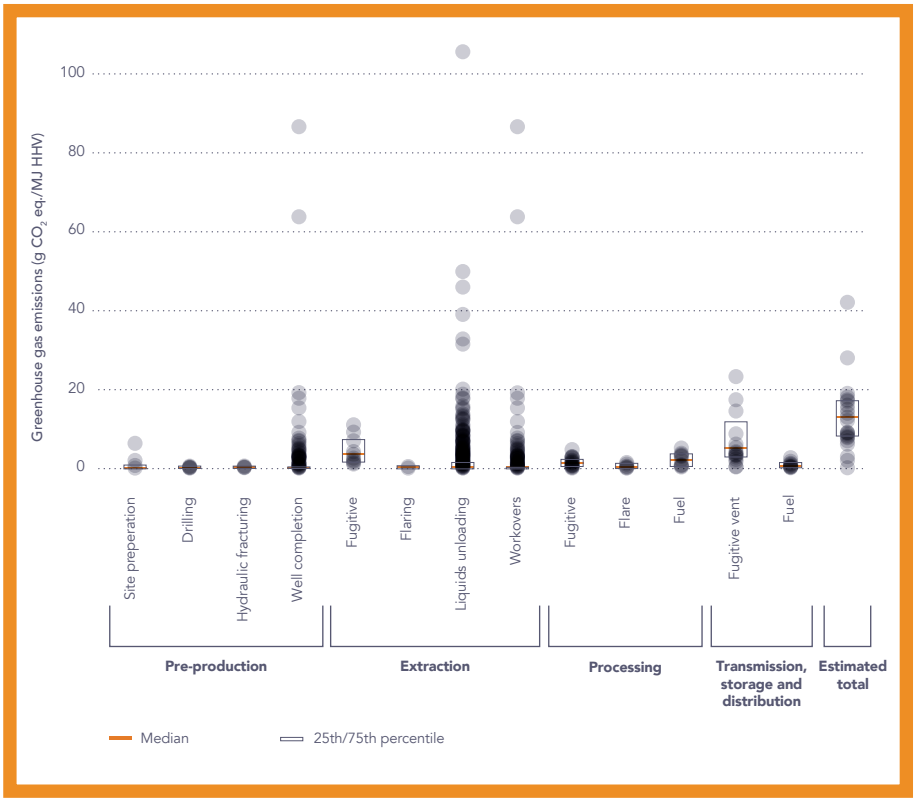


FIGURE ES-2 Greenhouse gas emission estimates across the natural gas supply chain
Each literature estimate of a supply chain stage is indicated as a grey circle. The median (orange), 25th percentile and 75th percentile (black box) estimate for each stage are shown with horizontal bars. Estimates of total supply chain emissions from individual studies are also shown. Methane emissions are converted to g CO_2 eq. using a GWP100 of 34 g CO_2/ g CH_4. A larger version of this graph can be found in section 3.1.

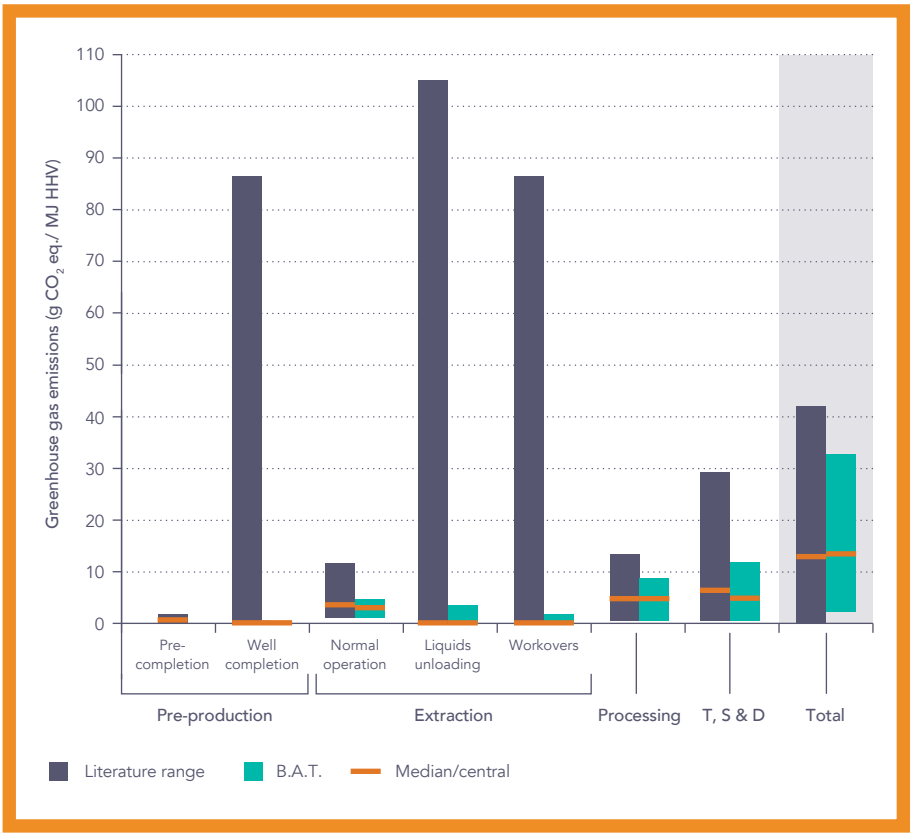
2. The key emission sources identified within the literature are from well completions, liquids unloading, pneumatic devices and compressors. During well completion for unconventional wells, the hydraulic fracturing fluid returns to the surface whilst the gas flow increases to the high initial production rate. Whilst some emissions estimates for this process are extremely high, primary data collected in recent years has shown that the use of Reduced Emission Completions (RECs) equipment can significantly reduce methane emissions to below 25,000 m^3 per completion, equivalent to 0.3 g CO_2 eq./ MJ HHV. In the US this equipment is now compulsory, which implies that this is no longer a significant source of emissions. It is important to note that, as this process is the main differentiator between unconventional and conventional extraction, this report concludes that emissions are comparable as long as methane is captured rather than flared.

Estimates of liquids unloading emissions are also highly variable. Whilst this may represent the greatest emission source for some wells, most wells do not vent at all during unloading. Current understanding of the distribution of emissions across the global well population is extremely poor within the literature and further research is required to detail and quantify the factors affecting unloading emissions such as well age, reservoir properties, equipment used and operational strategies.

3. Super emitters are a small number of high-emitting facilities that are skewing the emissions profile at every stage. This is implied in Figure ES-2 by the median (orange bar) and 75 percentile (black box) being positioned so low for each emission category. Super emitters have been found at various facilities across the whole supply chain including well completions, liquids unloading, leaking pipework, pneumatic devices and compressors. These large emissions are likely to occur due to the use of ineffective process equipment and poor operational and maintenance strategies. Again, it should be noted that if best available techniques and more stringent maintenance and operation procedures were applied, these high emissions would largely be eliminated.

4. This report estimates that the total supply chain emissions should lie within the range of 2.7–32.8 g CO_2 eq./ MJ HHV with a central estimate of 13.4 g CO_2 eq./ MJ HHV, if modern equipment with appropriate operation and maintenance regimes were used. However, there is significant potential for further reductions. This estimate is shown in Figure ES-3 alongside the original literature estimates. These revised 'Best available technique' (B.A.T.) values were estimated by removing a number of outlying literature estimates, excluding data that does not represent the use of emissions-minimising techniques (such as Reduced Emissions Completions and plunger lifts for liquids unloading) and excluding over-conservative fugitive emission assumptions. In the context of electricity generation and allowing for power plant emissions of 400 g CO_2 eq./ kWh, total GHG emissions would be 419–636 g CO_2 eq./ kWh electricity generated, with a central estimate of 496 g CO_2 eq./ kWh: this is well below typical GHG estimates of coal generated electricity of around 1,000 g CO_2 eq./ kWh. However, the supply chain emissions still represent a significant contribution to life cycle emissions: 4–34% for electricity generation. Furthermore, in a future scenario where Carbon Capture and Storage (CCS) is employed, the relative contribution from supply chain emissions would increase proportionally.

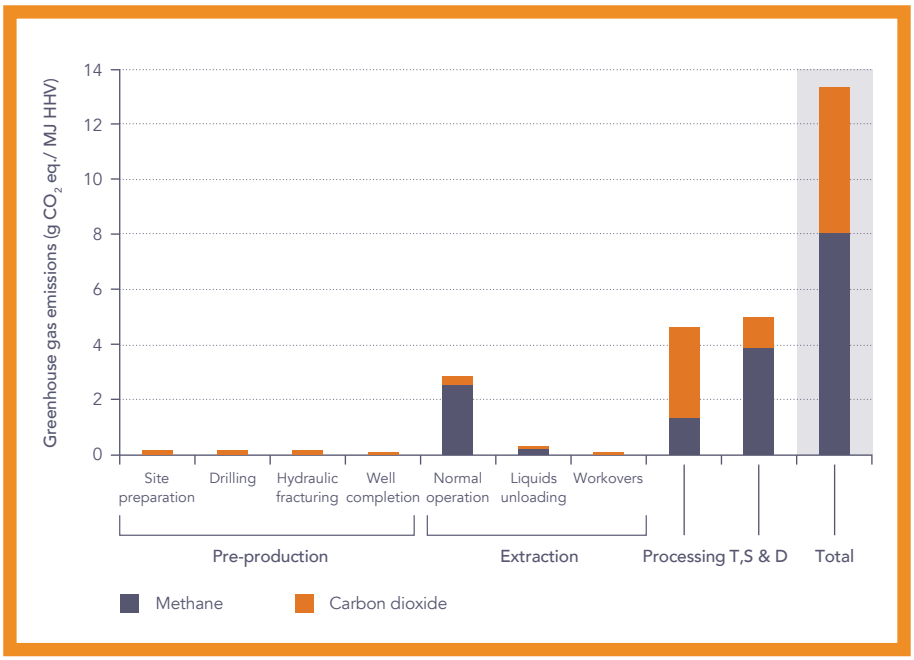
FIGURE ES-3
Greenhouse gas emissions across the natural gas supply chain for the literature values and a revised estimate, reflecting an effective operation, described as 'B.A.T.'
Low, central and high estimates of emissions are given. This is based on the authors' judgement from the literature reviewed and accounting for Reduced Emissions Completions during well completion and workovers. Note, total literature estimates are not a summation of individual stage estimates but estimates of the whole supply chain only.



Note that this revised estimate is based on the data that was available, which may be unrepresentative of the different supply chains across a multitude of regions, processes and regulations (see Key Finding 6). The revised estimate is not a target emission to be achieved, which could be much lower.

Determining the degree to which supply chain emissions could feasibly be reduced should be the subject of further research, in the context of understanding the full potential for natural gas to contribute to a lower carbon energy mix. Opportunities for further reductions in particular are fugitive emissions during extraction, transmission and distribution stages, as illustrated in Figure ES-4, which shows the remaining emissions from the reduced 'B.A.T.' estimate. With reduced emissions during well completions, liquids unloading and workovers (periodic well maintenance or re-completion), the majority of emissions originate from methane leaks and vents. Emissions across the transmission stage are highly uncertain, due to both the lack of data and the high variability in transmission distances across different supply chains.

FIGURE ES-4
Central estimates of greenhouse gas emissions across the supply chain where best available techniques are applied, split into methane and CO_2 emissions, reflecting an 'effective' operation during key supply chain stages
A value of 34 for GWP100 of methane is used. The category 'T, S & D' refers to the transmission, storage and distribution stages.



5. Emissions estimates also vary greatly due to methodological differences in estimation. Firstly, many top-down methane emission measurements have been carried out, which involve measuring or inferring the concentration of methane in the atmosphere within a region, and subsequently allocating the detected emissions to specific emission sources within that region. These estimates are useful in validating (or otherwise) point source emission estimates and identifying whether bottom-up estimates may be underestimating emissions. However, they provide little detail in terms of detecting where such underestimates may occur. Bottom-up point source measurement in combination with local leak detection operations could help to prevent missing unknown emission sources.

Other methodological assumptions within life-cycle assessment studies of the natural gas supply chain also vary significantly across the literature and can have a major effect on the estimated emissions. Important assumptions include:

- the assumed global warming potential of methane;
- the assumed total production volume of a well;
- the allocation of emissions to other co-products such as natural gas liquids;
- different boundary limits across different life cycle studies; and
- the assumed methane content of the extracted natural gas.

Specifically, more data is required for offshore extraction, coal bed methane extraction, liquids unloading, well completions with RECs and transmission and distribution pipelines.

6. Whilst there has been a recent drive to collect primary emissions data, there is still an incomplete and unrepresentative data set for a number of key emission sources. Specifically, more data is required for offshore extraction, coal bed methane extraction, liquids unloading, well completions with RECs and transmission and distribution pipelines. There is also a lack of transparency in data and a lack of accounting for methane emissions across all of the LNG stages. In terms of regional distribution of estimates, the available data is almost exclusively from the US. Whilst this may be applicable to other regions, both geological formations and regional regulation play a large part in the supply chain emissions.

7. Further research is required in order to determine how much supply chain GHG emissions could be reduced. It is clear that the potential supply chain GHG emissions could be reduced significantly from current estimates, but more research is required to define both by how much emissions could be reduced, and by which technological, operational or regulatory mechanisms these reductions could be achieved. As well as the requirement for more representative emissions data as mentioned above, further research is required in the following areas.

- To determine the potential role of natural gas in low carbon energy systems, a quantification of the potential reduction in supply chain emissions is required. The use of emissions-minimising technology and operation may be constrained by economic feasibility, whilst geological characteristics and regulation may also limit emissions minimisation.
- A greater causal analysis of the factors affecting different supply chain emissions is required in order to understand the mitigation potential at each stage. Such factors include the selection of equipment, operational practices, the regulatory environment and reservoir properties. This is particularly salient to the liquids unloading process and requires analysis from engineering, economics and political perspectives. Analysis on the impact of regional regulation on the emissions associated with the supply chain is required, in particular with respect to continuous monitoring and 'super-emitting' facilities. Targeting such facilities would yield the greatest environmental improvements and improve the contribution of natural gas towards a low carbon energy system.

List of figures

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List of abbreviations

AGA	American Gas Association
ANGA	America's Natural Gas Alliance
API	American Petroleum Institute
AR4	IPCC Fourth Assessment Report
AR5	IPCC Fifth Assessment Report
CBM	Coal bed methane
CCS	Carbon capture and storage
CH_4	Methane
CO_2	Carbon dioxide
CO_2 eq.	Carbon dioxide equivalent
DEA	Diethanolamine
EIA	Energy Information Agency
EPA	Environmental Protection Agency
ES	Executive Summary
EUR	Estimated ultimate recovery
g	gram
g CO_2 eq./ MJ HHV	g of CO_2 equivalent per megajoule high heating value
Gg	Gigagram
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GRI	Gas Research Institute
GTI	Gas Technology Institute
GWP	Global Warming Potential

GWP100	Global Warming Potential over a 100 year period
GWP20	Global Warming Potential over a 20 year period
H_2S	Hydrogen sulphide
HHV	High Heating Value
Hr	Hour
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organisation for Standardisation
kg	Kilogram
km	Kilometre
kW	Kilowatt
kWh	Kilowatt hour
L	Percentage of gas that is extracted but not delivered to user
LCA	Life cycle assessment
LHV	Low Heating Value
LNG	Liquefied Natural Gas
M&R	Metering and Regulating
mbarg	Millibar gauge
MEA	Monodiethanolamine
min	Minute
Mg	Megagram (equivalent to metric tonne)
MJ	Megajoule
MWh	Megawatt hour
N_2	Nitrogen
NGL	Natural Gas Liquids
NGO	Non-governmental organisation
OECD	Organisation for Economic Cooperation and Development

pa	Per annum
ppm	Parts per million
REC	Reduced Emission Completion
RF	Radiative Forcing
Scf	Standard cubic feet
SGI	Sustainable Gas Institute
t CO_2 eq.	Tonnes of CO_2 equivalent
T, S & D	Transmission, storage and distribution
Tg	Teragram
TPA	Technical Policy Assessment
UKERC	United Kingdom Energy Research Centre
vol	Volume
W/m^2	Watts per square metre
Yr	Year
ρ	Density

Contents

1. Introduction

The magnitude of methane and carbon dioxide (CO_2) emissions from the natural gas supply chain is a controversial topic. Since 2010, a number of studies performed by governments, universities, private and institutional bodies have concluded that methane emissions in particular are higher than previously estimated. However, these results have generated much discourse and uncertainty over how they are estimated, the data sources used and assumptions made.

> Since 2010, a number of studies performed by government, university, private and institutional bodies have concluded that methane emissions in particular are higher than previously estimated.

The Sustainable Gas Institute[1] (SGI), based at Imperial College London, has conducted this review of the topic in order to shed light on the debate. This review synthesises and critiques the large body of evidence on the magnitude of methane and CO_2 emissions associated with the natural gas supply chain. In particular the review focusses on the range of emission estimates, the associated uncertainty, methodological differences and the gaps in the evidence where further work is needed. The method applied in the review is based on the approach developed by the UK Energy Research Centre (UKERC) Technical and Policy Assessment (TPA) team at Imperial College London, which was adapted to the needs of the SGI.

1.1. The context

Global production of natural gas has risen at a rate of 3% per annum over the last decade [1] and this may increase further due to the drive to develop unconventional gas resources. The potential of unconventional gas as a low cost and secure energy source appeals to energy policy makers over other price-volatile fossil fuel imports. Additionally, natural gas may be appealing from a climate change mitigation perspective as electricity generation from natural gas typically emits less CO_2 per unit of electricity generated than coal-sourced electricity [2].

However, there is still uncertainty and debate regarding the contribution that natural gas could or should make to meeting global climate change

1. Sustainable Gas Institute (SGI) is an academic research, education and knowledge transfer institute which launched in 2014. The SGI leads research and defines the innovative technologies that enable natural gas to play a key role in a low carbon world.

targets. Firstly, even though CO_2 emissions are lower than for coal, natural gas combustion still emits CO_2 which contributes to global greenhouse gas emissions.

Secondly, although combustion CO_2 emissions of natural gas are lower than from coal, overall CO_2-equivalent methane emissions may be significant. Methane is a much more potent greenhouse gas (GHG) than CO_2, particularly over short time-scales and consequently as methane emissions increase, the reduced end-use CO_2 emissions compared to other fossil fuels can be eroded. There is concern that fugitive and vented methane emissions from the natural gas supply chain could be larger than originally expected [e.g. 3].[2] The estimation of overall methane emissions across the natural gas supply chain has been debated hotly in the past five years, with various estimations resulting in inconsistent conclusions. The following factors are matters of particular contention [10]:

- The magnitude and range of methane emissions across the natural gas supply chain.
- The methods, data and assumptions used to estimate these emissions.
- The 'global warming potential' of methane compared to CO_2 and the timescale over which it should be considered.

1.2. Aims and scope

The aim of the review is to determine the current state of knowledge of the methane and CO_2 emissions associated with the global natural gas supply chain. In particular the review seeks to answer the following questions:

1. What is the range of estimated CO_2 and methane emissions from the supply chain?
2. Which of the estimates or data are widely accepted and which are controversial?
3. What are the reasons for the controversial or differently estimated emission levels?
    a. Different estimation methods
    b. Lack of data, or difference in assumptions made
    c. Different natural gas extraction points, processes, transport and storage steps

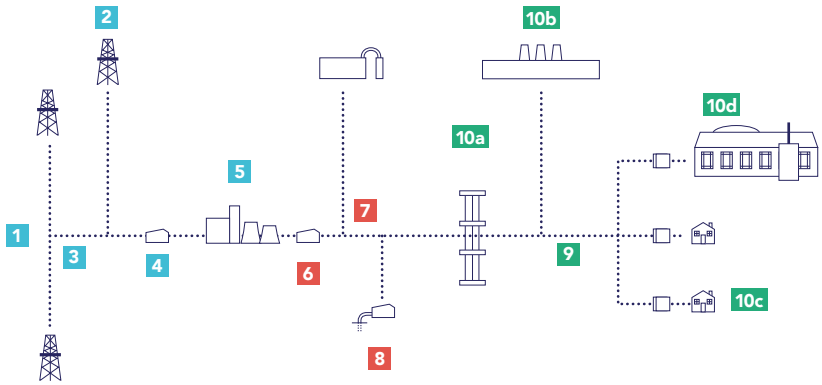
The scope of the review is to include all widely used methods of extraction, processing and transportation of natural gas across the globe. This includes conventional and unconventional extraction, processing of different grades of natural gas (i.e. different composition), piped transmission, storage and distribution, and LNG transport and delivery.

2. It should also be noted that methane emissions from coal extraction sites are also not insignificant, with studies in the literature reporting estimates from 0.94 to 3.46 g of CH_4/kWh electricity ultimately generated [5–9].

The types of well that are included within the scope of this review are: conventional onshore and offshore, shale gas, tight sands and coal bed methane (CBM). Associated gas, which is gas released from oil wells (containing less than 12,500 scf gas/ barrel of oil [11]) is excluded from the scope, due to the issue of allocating emissions between co-products (see section 4.4.5 'Methods of measurement and estimates' for more detail).

The scope also does not include the use-phase of natural gas, i.e. natural gas combustion for electricity or heat. The boundary limit of the study is the delivery of natural gas to the user. A diagram of the natural gas supply chain and the boundary of this study is given in Figure 1.

FIGURE 1
Diagram of the natural gas supply chain
Sourced from the EPA Natural Gas STAR Program [12].



Production and processing
1. Drilling and well completion
2. Producing wells
3. Gathering lines
4. Gathering and boosting stations
5. Gas processing plant

Natural gas transmission and storage
6. Transmission compressor stations
7. Transmission pipeline
8. Underground storage

Distribution
9. Distribution mains

Regulators and meters for:
- 10a. City gate
- 10b. Large volume customers
- 10c. Residential customers
- 10d. Commercial customers

1.3. Review methodology

This report describes the results of a comprehensive review of academic, industrial and governmental literature, drawing on the UK Energy Research Centre (UKERC) Technical and Policy Assessment (TPA) group[3] approach, which has been adapted to the needs of the SGI. The methodology uses systematic and well-defined search procedures to document the literature review, providing clarity and transparency of analysis. Prior to the review, an external expert advisory panel was appointed with a broad range of perspectives to

3. Source: www.ukerc.ac.uk/programmes/technology-and-policy-assessment.html

consult on the initial framing and scoping of the review. Once the review was completed, the expert panel reviewed and commented on the paper prior to publication. The assessment process carried out is presented in Figure 2.

Scope the project	Solicit expert input	Review the literature	Synthesis and analysis	Prepare the draft report	Expert panel review and refine	Publish and promote
TASKS						
• Write a scoping note, outlining aims and search and review protocols	• Appoint expert panel • Solicit expert panel comments on scoping note • Finalise aims and search and review protocols	• Apply protocol to literature search • Detailed and transparent 'trawl' • Identify relevant sources	• Apply protocol for evaluation and synthesis of literature	• Write preliminary draft report	• Solicit expert panel comments on draft report • Revise draft report	• Design and format report • Publish and publicise report • Launch event
OUTPUT						
• Submit scoping note to expert panel	• Expert panel review of scoping note	• Literature database		• Draft report	• Expert panel review of report	• Publish report

FIGURE 2
Diagram of the systematic review methodology

1.4. Report structure

The rest of this report is structured as follows:

- Section 2 clarifies and defines a number of issues surrounding the natural gas supply chain and the debate on associated emissions.
- Section 3 documents the range of emission estimates found in the literature for each stage of the supply chain.
- Section 4 delves further into the issue, describing the key emission sources, the (lack of) data availability and representativeness and other methodological problems associated with emission estimates.
- Section 5 provides key outputs and conclusions from the review in terms of the synthesised emissions data. A description of the key uncertainties and technological challenges are also identified as future research needs.

2. How it works and what it means: clarifications and definitions

This section describes the various types and stages of the natural gas supply chain and provides clarification of the various terms and definitions commonly used within the industry. Specifically, descriptions are provided for:

- the composition of natural gas;
- conventional and unconventional wells;
- supply chain stages;
- sources of supply chain emissions;
- metrics used in emissions estimates;
- issues associated with global warming potentials; and
- methods of estimating emissions.

2.1. Natural gas composition

The composition of natural gas extracted from different reservoirs can be very different. Typically, natural gas predominantly comprises of methane, with smaller proportions of ethane, propane and heavier alkanes, nitrogen, carbon dioxide and hydrogen sulphide (H_2S). Non-associated natural gas, i.e. gas wells with only small quantities of heavier hydrocarbons, tend to have a much higher methane content (95–98% by volume) than associated gas (60–80%) [13]. The CO_2 content can be 0–50% or even higher. Likewise nitrogen and hydrogen sulphide could be up to 25% and 15%, respectively. Typically the gas composition is categorised as follows:

- sweet dry gas (low H_2S, CO_2 and heavy alkanes)
- sour dry gas (high H_2S, CO_2 but low heavy alkanes);
- sweet wet gas (low H_2S, CO_2 but high heavy alkanes); and
- sour wet gas (high everything).

Due to these impurities, natural gas requires processing to meet the specification of 'sales' gas. The specification of sales gas varies by region and is often measured by the higher heating value (HHV): the amount of energy released by combusting a unit volume of natural gas product, assuming that the latent heat of vaporisation of water is recovered. There are a range of allowable gas product HHVs for each country [14], as well as maximum quantities of impurities [15].[4]

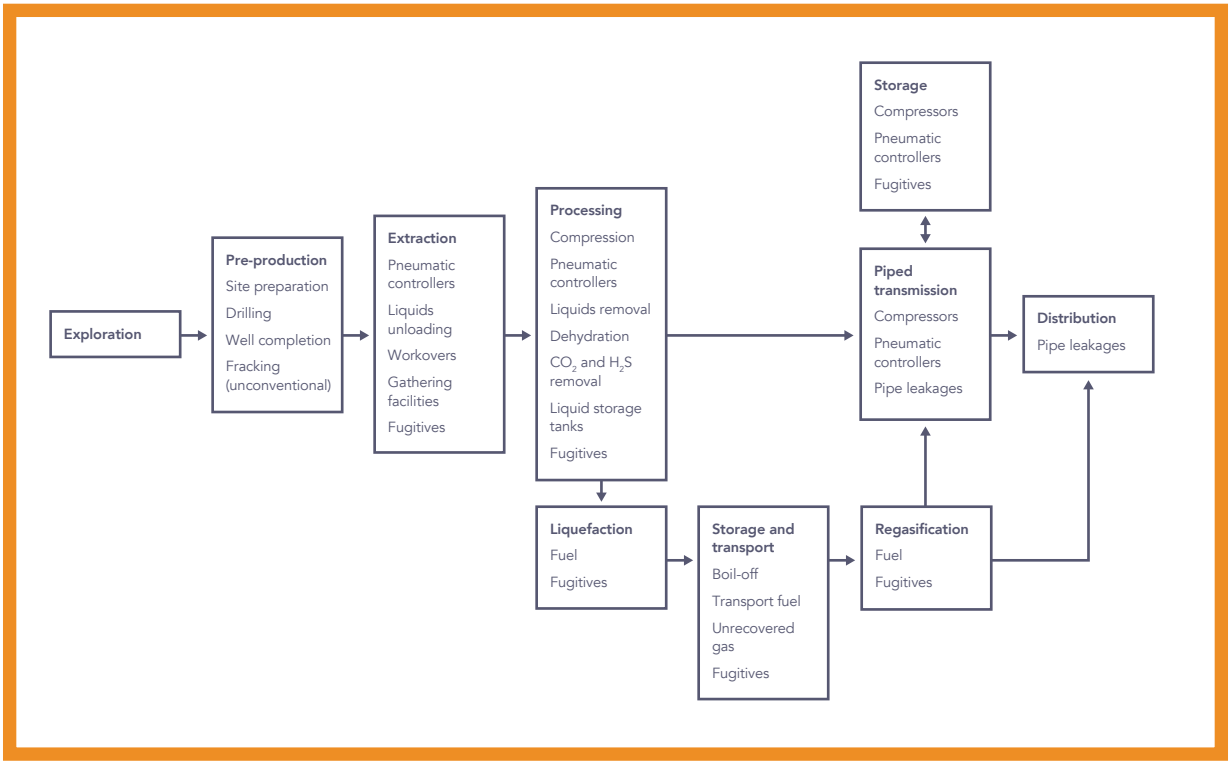
4. For example; carbon dioxide (2.5% mol/mol for Denmark), oxygen (0.1%), H_2S (5 mg/m^3) and water (a dew point of less than 3°C at 80 bar). Product quality gas is typically above 90% methane [15].

2.2. Conventional and unconventional wells

There are a number of types of gas wells, broadly categorised as conventional and unconventional wells. Conventional gas wells, both onshore and offshore, use vertical drilling techniques. The extraction of conventional reservoirs requires very little forced stimulation of initial gas flow [16]. Offshore reservoirs that are extracted tend to be larger than onshore wells, in order to achieve economic feasibility. This is because offshore wells are more expensive to extract than onshore wells due to the distance from land, the cost of well completion and the construction of offshore extraction and processing platforms. Therefore more gas must be extracted to produce the same amount of profit as an onshore well.

Unconventional gas wells are a set of different well formations that normally need to be stimulated in order to produce sufficient gas flow, categorised as tight sands, shale gas and coal bed methane (CBM). Tight sand and shale gas reservoirs differ from conventional gas as they exhibit a low permeability and low porosity, which makes it harder to extract the gas. Stimulation is required to produce sufficient gas flow, such as by hydraulic fracturing (and some acidising methods). Unlike tight sands, horizontal drilling is also normally needed for shale gas, in order to get access to more of the gas [17]. CBM lies within the seam of a coal bed formation and shallow horizontal drilling is required to extract the gas [16]. Some coal seams also have low permeability and so hydraulic fracturing is needed (Grudnoff [18] estimates 25–40% of CBM wells require fracturing).

FIGURE 3
The natural gas supply chain
Listed within each stage are the key processes and/or emission sources. Note, emissions are listed as examples and this does not constitute a comprehensive list.
H_2S = Hydrogen Suphide



2.3. The supply chain

Figure 3 illustrates the supply chain, from extraction to the point of delivery, including the key aspects of each stage in terms of emissions. The following sections describe each stage of the supply chain, focussing on what the processes are, how they work and why they are required.

2.3.1. Exploration and pre-production

Before extraction begins, the search for a viable gas well involves a number of seismology tests and preliminary drilling, in order to estimate the availability and quantity of reservoir gas. In the case of shale gas, wells may be hydraulically fractured to characterise the gas and assess economic viability [19].

Once an economically feasible reservoir is identified, the site is prepared by clearing over-ground vegetation and constructing the infrastructure: access roads and facilities, drilling and extraction equipment. The wells (other than the exploratory well) are then drilled. Wells exist at a variety of depths (1km to over 10km) and some wells require horizontal drilling, such as with shale gas [19].

> Hydraulic fracturing is used not only for shale wells, but also for tight sands and coal bed methane wells. However it is not normally carried out for conventional wells.

Well completions and hydraulic fracturing

Every gas well regardless of the type of formation must be 'completed' once it has been drilled. This consists of several operations such as inserting the casing, cementing and perforating the well-casing. This is also the stage where hydraulic fracturing is carried out for unconventional gas sources [20].

Hydraulic fracturing (fracking) is carried out by pumping large volumes of fracking fluid at high pressure (approximately 80 bar) into the well. The volume of water used is extremely variable, often estimated in the order of 10,000 m^3 [21, 22]. One study of the Barnett Shale [23] cites 5th and 95th percentile ranges of 5,000 and 33,000 m^3. Fracking fluid is chiefly composed of water (approximately 90% by volume), sand (approximately 8%) and other chemicals such as hydrochloric acid, gelling agents and petroleum based surfactants [19]. The creation of fracking fissures occurs in stages along the well (sometimes up to 20 stages, depending on the size of reservoir). Once the fracturing is complete, a period of 'flowback' ensues for normally between three and 10 days, where some of the fluid returns to the surface, alongside large slugs of gas. The flow of gas increases up to the initial production rate, where completion ends and production begins. The flowback fluid, which contains many impurities from the gas well, is captured and must be treated prior to disposal.

2.3.2. Extraction

Once the well is completed and connected to downstream gathering equipment, extraction begins. The extraction stage involves collecting the raw gas from a variety of wells, gathering the flows together using piping manifolds whilst controlling the flow rate and pressure using compression and flow regulation.

Workovers

The gas flow from a well decreases over time because, as the quantity of gas in the well decreases, so does the well pressure that forces the gas up to the surface. In order to re-stimulate the gas well, the well may require a workover, or recompletion.

During a workover, there are a number of processes that may occur, but these are all for the purpose of increasing the flow of gas from the well. Such processes are repairing leaks, perforating new parts of the well bore or cleaning existing perforations and for unconventional gas, this may involve hydraulically fracturing the well again to release more gas [16]. Liquids unloading is not considered to be part of workover operations, but instead a separate set of processes, described below.

Liquids unloading

A number of times during the lifetime of the well extraction, the well flow may become impeded due to the accumulation of liquids within the well. At the early stages of well production, gas velocity is high, which allows liquids to be brought to the surface. However, as the well matures the flow and velocity of gas reduces preventing the entrainment of these liquids. Thus, liquids may accumulate at the bottom of the well and as the liquid level increases this further impedes gas flow. Liquids unloading is a set of processes that are carried out to remove the flow restriction and increase production [24]. Liquids unloading may be required for any gas well, conventional or unconventional. It has been suggested previously that shale gas wells do not require liquids unloading because the liquids are unloaded during the workover process instead [16] and that CBM does not require liquids unloading. However, this has since proved to be incorrect [25].

> Liquids unloading may be required for any type of gas well, conventional or unconventional.

The processes that may be employed to conduct liquids unloading are [24]:

- **Well blowdown,** involving temporarily shutting in the well to increase well pressure and then venting to atmosphere.
- **Plunger lift,** placed in the well acting like a piston between the pressurised gas and liquids, removing liquids as it moves towards the surface.
- **Artificial lift,** similar to a plunger lift but this process uses a pump to drive the lift and is used when the well does not have sufficient shut-in pressure to operate the standard plunger lift.
- **Velocity tubing,** smaller diameter tubing is installed in wells with typically lower flow but higher well pressures, in order to increase the gas velocity and thus helps to dislodge the liquids.
- **Well swabbing** to remove the liquids. A large wire with a rubber cup is dropped down the tubing and collects liquids as it is pulled back to the surface.
- **Foaming agents,** surfactants are injected into the well casing annulus (between the well casing and tubing). When the gas flows through the surfactant, foam is created with the blocking liquids, which are removed more easily in foam form.

2.3.3. Processing

Depending on the quality of the raw gas, it may be necessary to remove contaminants to meet the gas sales specification. Common contaminants are water, heavy hydrocarbons, CO_2, hydrogen sulphide (H_2S) and nitrogen.

Water is normally removed using a glycol absorption column. It is also possible to flash separate the water by boiling off lighter compounds but this is generally less economically efficient [26]. Heavy hydrocarbons are also often removed by absorption, but not glycol (which is hygroscopic), instead an absorbing oil is used. Recovery of the absorber oil occurs by boiling off the butanes, pentanes etc., which have lower boiling points [26]. The removal of H_2S and CO_2 is also usually by absorption, with amines such as monoethanolamine (MEA) or diethanolamine (DEA). Solid adsorbants can also be used to remove H_2S and CO_2, such as iron oxide (sponge).

Within the processing stage, compression systems are often installed in order to increase gas pressure to the transmission pipeline.

2.3.4. Transmission

Once processed, the gas is sent through long distance pipeline networks, either nationally or transnationally. Gas may travel distances of hundreds or thousands of kilometres, therefore regular compression stations are required throughout the network to drive the gas and overcome pipeline friction. Transmission lines operate at up to approximately 100 barg [27, 28].

2.3.5. Storage

The demand for gas varies throughout the year, with winter in the northern hemisphere causing a particular surge in demand. As supply rates tend to be relatively inelastic, most countries have underground storage reservoirs that can be called upon to meet spikes in demand. According to the Energy Information Agency [29], the 2013 US storage capacity comprised 77% depleted gas reservoirs, 16% depleted aquifers and 7% salt caverns. A small percentage of the gas that is injected underground for storage cannot be recovered again later and is known as base gas. Stored gas often picks up water during underground storage and therefore requires dehydration prior to being released back into the distribution network. It is therefore common for storage facilities to have both dehydration and compression facilities.

2.3.6. Distribution

The domestic distribution system begins at the city gate stations where gas from the transmission network is reduced in pressure to feed into the domestic consumer pipeline system to around 25 mbarg, where it will primarily be used for residential heating and cooking. Alternatively the gas may be sent from higher pressure pipelines to commercial users such as chemical production facilities.

2.3.7. LNG liquefaction, storage and distribution (transport)

A significant percentage of the world's natural gas reserves are geographically isolated from energy markets. Transportation by pipeline is efficient for high volumes of consistent demand and shorter distances, but lacks flexibility in demand and location. Instead, natural gas can be compressed and shipped. In order to make shipping economically feasible, it is liquefied so that the energy density is much higher. Large quantities of natural gas are found in Australia, Algeria, Qatar, Iran, Malaysia, Brazil, Trinidad and Tobago, and Indonesia. Without LNG, all of these gas fields would be stranded from markets by either politically bureaucratic or regulatory difficulties with transnational transmission or extremely large distances.

The liquefaction process involves cooling the gas to a temperature of approximately -160°C and then maintaining that temperature by storing the liquefied gas in cryogenic containers. Prior to cooling, the gas must be processed to remove any impurities that will freeze, such as water, CO_2, H_2S, N_2 and heavy hydrocarbons. LNG is typically in the range of 95 to 100% methane; small quantities of impurities such as N_2, ethane and butane will not cause problems to the liquefaction process.

2.4. Sources of emissions in the supply chain

There are several processes by which CO_2 and methane are emitted from the natural gas supply chain.

Generally, they are by the following routes:

- **Combustion emissions:** many parts of the supply chain require heat or electricity to operate and this demand is typically met by natural gas combustion [19], resulting in CO_2 emissions. Incomplete combustion can lead to some hydrocarbon emissions including methane [19].
- **Vented and flared emissions:** at various points during the life cycle of natural gas, methane and CO_2 must be vented, for example during well completion and processing stages [22]. Capturing (for example during well completions), or flaring of vented gas is the norm within the oil and gas industry, wherever feasible.
- **Fugitive emissions:** unintentional gas leaks may occur at any point of the supply chain, but are typically associated with extraction and pipeline transport phases.

The definition of 'fugitive' is not uniform across the literature and may cause confusion. Within this report, a fugitive emission is defined as an unintentional leak, as opposed to a vented emission which is an intentional emission. However, both forms of emissions are addressed within this report.

2.5. Metrics used to show emissions

Measurements of methane, CO_2 or GHG emissions across the supply chain are given in a wide variety of metrics across the literature, dependant on the boundary considered and the purpose of each study. Many studies estimating methane emissions present results per cubic metre of produced gas, or per unit of electricity generated by a natural gas electricity generation plant. This is a levelised value, where the quantity of emissions is divided by a functional unit. It is useful to express emissions in this form because these emissions can then be compared to other fuel sources or means of producing the same quantity of gas. The main functional units used in supply chain emissions estimates are per:

- **1 m^3 of delivered natural gas.** Total emissions are divided by the total expected volume of gas delivered to the consumer, which may be domestic or commercial.
- **1 m^3 of produced/extracted natural gas.** Total emissions are divided by the total expected volume of gas extracted from the well.
- **1 MJ of energy content of delivered natural gas.** Total emissions are divided by the total expected quantity of embodied energy delivered to the consumer (as a higher or lower heating value).
- **1 kWh of generated electricity (fuelled by gas).** Total emissions are divided by the expected total quantity of electricity that would be generated from a power plant using the natural gas.

- **The total volume of gas produced by a well in its lifetime.** Total emissions are estimated for the lifespan of the well.
- **The total volume of gas produced by a nation.** Emissions from each supply chain stage are multiplied by the activity of each stage within a nation to estimate annual national emissions.

The use of many different functional units within the literature makes comparisons across different studies very difficult. Additionally, some studies give insufficient information to allow an exact identification of the functional unit. For example, a number of studies express emissions 'per MJ of natural gas' [30]. This implies that it is a MJ of energy content within the gas, but does not state whether it is the energy content of extracted gas or delivered gas, which may be very different. Recently, a number of studies have been published which attempt to 'harmonise' different emission estimates [e.g. 30, 31, 32], which involves meticulous comparison of the different assumptions and units used, and an attempt to transform the different results into the same metrics. This is a very useful process and these studies are used within this review to compare different literature results. However, a formal harmonisation procedure is outside of the scope of this review.

For this report, in order to aggregate and compare results, GHG emissions are converted into a 'per MJ of energy content (HHV) of delivered gas' basis and a 'per kWh of generated electricity' basis. The tables within the Appendix also show these emissions on a 'per m^3 of produced gas' basis, alongside the calculation method. The assumptions used to convert literature values to these units are given within the Appendix.

Methane-only emissions are expressed in this paper as a percentage of the total quantity of methane extracted (volume methane emitted/ volume methane extracted). Note that this is only equivalent to the volume of *gas* emitted per volume of extracted *gas* when the emission occurs prior to the processing stage, at which point the methane content of the gas changes. As the gas is purified and the methane content increases, a release of 1 m^3 of 'sales spec' gas is equivalent to more than 1 m^3 of raw gas, therefore it becomes inconsistent to express emissions as a percentage of gas extracted unless a conversion factor is applied. For example, where 80% (by volume) methane gas is processed to 95% methane, a transmission-stage gas release of 1 m^3 is equivalent to a gas release of 1.19 m^3 of gas extracted. These percentage methane/gas emission metrics are given in various different forms and with different levels of transparency across the literature, so where possible, this paper has converted these values to a percentage of methane emitted per volume of methane extracted. Note that volumetric units are given with respect to American standard conditions, 15.6°C and 1 atm, as the large body of estimates are in this format and to minimise data manipulation.

As well as using a variety of unit denominators, emissions are also cited in different numerator units, such as a mass of carbon, CO_2, methane or carbon dioxide equivalent (CO_2 eq.). CO_2 eq. is the convention used in this report and is described in Box 1.

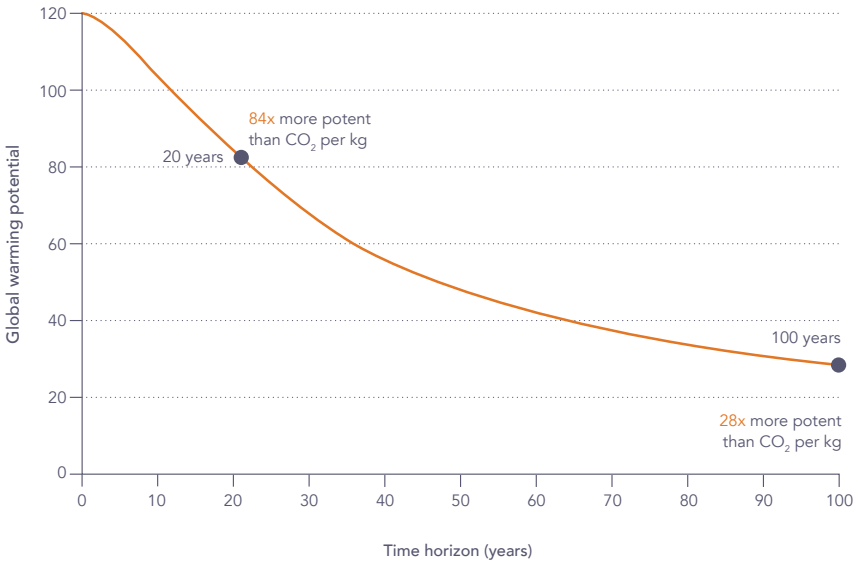
Box 1: Global warming potential of methane

Methane is known to be a more potent greenhouse gas than CO_2, but understanding how much more potent is complicated and has led to misunderstandings within the literature. The instantaneous climate forcing of a methane emission 'pulse' is approximately 100-120 times greater than CO_2 [38, 189] but this decreases significantly over time because methane oxidises to CO_2 after around 12 years on average [36].

Global Warming Potential (GWP) is a metric developed and adapted by the Intergovernmental Panel on Climate Change [33] to account for the trade-offs between different types of GHG [34]. It is defined as the **time-integrated** radiative forcing of an emission pulse of the gas in question, relative to that of CO_2, over a defined **time horizon**. The key parts of this definition are that GWP is time-integrated and that it is over a specific time horizon, which are explained below. The GWP factor for each GHG has also been developed further in recent years to account for various indirect climate forcing effects, such as cloud albedo and carbon-climate feedbacks [35, 36].

The GWP of methane varies depending on which **time horizon** is chosen, as shown on Figure 4. A 100 year time horizon (GWP100) remains the most common metric used for abatement technology evaluation. However, 20 year time horizons are also used, which can significantly affect results, often leading to disagreement in the literature [3, 38]. The GWP100 for methane is 34 g CO_2/g CH_4, meaning that a methane emission has had a climate forcing impact 34 times greater than CO_2 on average over the 100 years after the emission.

FIGURE 4
Illustration of the changing GWP of methane over time.
Sources: Alvarez et al. [38] and Allen et al. [37]. Note, these numbers do not include the effect of carbon-climate feedback resulting in slightly lower values than expressed within this section (e.g. a GWP100 of 28 rather than 34).



The **time-integrated** quality of GWP means that it is the average climate forcing effect over the time horizon being considered, rather than the effect at a specific point in time after an emission. For example, the average effect of a methane emission pulse over 100 years is 34 (GWP100), but the impact at the end of the 100 years is almost zero.[5]

The use of the time-integrated GWP can be confusing for non-CO_2 related decision making, because it does not specify a set time point for which climate change impacts are relevant. In order to determine whether a non-CO_2 emission pulse is important depends on the intended climate stabilisation level (W/ m^2), the timing of that stabilisation, and the background emissions prior to and after the pulse.

Indeed, the way that GWP is used in most abatement studies does not take into account the timing of emissions at all. Typically, one metric (e.g. GWP100) is used to estimate methane emissions of a well over its lifetime. However, as a well may be active and emitting for 30 years or more, this means that the time horizon is not fixed at one point in the future.

There is no single correct time frame to use, as it depends on the reasons for which the estimation is being carried out. The choice is a policy decision: are we concerned about a short-term or long-term rise in climate temperature? As the time of required climate stabilisation grows closer, the impact of methane emissions grows stronger. Conversely, an emission pulse of methane in 2015 has little effect on climate forcing in 2115. Many countries have committed to reducing GHG emissions by 2030 or 2050, but these are interim targets with the aim of long term decarbonisation. Alvarez et al. [38] suggest that for technological environmental analyses, it is more appropriate and transparent to plot estimated GHG emissions over different time horizons. This paper describes combined methane and CO_2 emissions with a GWP100, as well as conducting an assessment on the effect of methane GWP on total GHG emissions within the Section 4.4.1.

2.6. Methods of estimation: Top-down and bottom-up

There are a number of different techniques for measuring methane emissions, which are generally characterised as either top-down or bottom-up. Bottom-up methods measure methane emissions from a sample of sources directly at the emission point intended to be representative of part of the supply chain and then aggregating and extrapolating these measurements for a whole region or process [37]. Top-down methods estimate emissions from a region by sampling

5. Note, this does not take into account the effects of the CO_2 that is borne from the oxidation of CH_4 in the atmosphere. 1 g of methane will oxidise to form 2.75 g of CO_2. Accounting for this adds 2 and 1 to the GWP20 and GWP100 respectively.

atmospheric concentrations of methane and attributing the contribution made by different activities [37]. This can be done by measuring atmospheric methane concentrations from fixed ground monitors [39, 40], mobile ground monitors [41, 42], aircraft [43–45] or satellite monitoring platforms [46]. Methane emissions are allocated to the natural gas industry either by using an atmospheric component 'fingerprint'[6] method [47] or by subtracting estimates of other sources of methane emissions, such as background methane concentrations, agriculture, waste management, etc. There are significant limitations associated with both top-down and bottom-up methods, which are discussed further in section 4.4.1.

The definition of top-down analysis differs across the literature. Some regard top-down estimation as an application of bottom-up emission factors to national scale emission inventories [e.g. 48]. Within this report, top-down estimates are defined as using atmospheric measurement as opposed to a point source measurement followed by extrapolation (bottom-up).

6. The 'fingerprint' method is based upon knowing the concentration of another (or more than one) compound within natural gas, normally an alkane. The detection and measurement of these compounds from the atmosphere can be used as a 'fingerprint' to infer the relative emission rate of natural gas.

3. What are the emissions estimates?

Overall, 424 papers were reviewed, which included academic papers, government reports and industry and NGO white papers. Of these, 240 studies were included after an assessment of relevance and quality. Over half of the papers were based on the US or North America (54%). The majority of the papers that were not based on North America used data from the US. Other studies were based on a global estimate (13%), Russian gas networks (5%) or the UK (6%).

Overall, 424 papers were reviewed, which included academic papers, government reports and industry and NGO white papers.

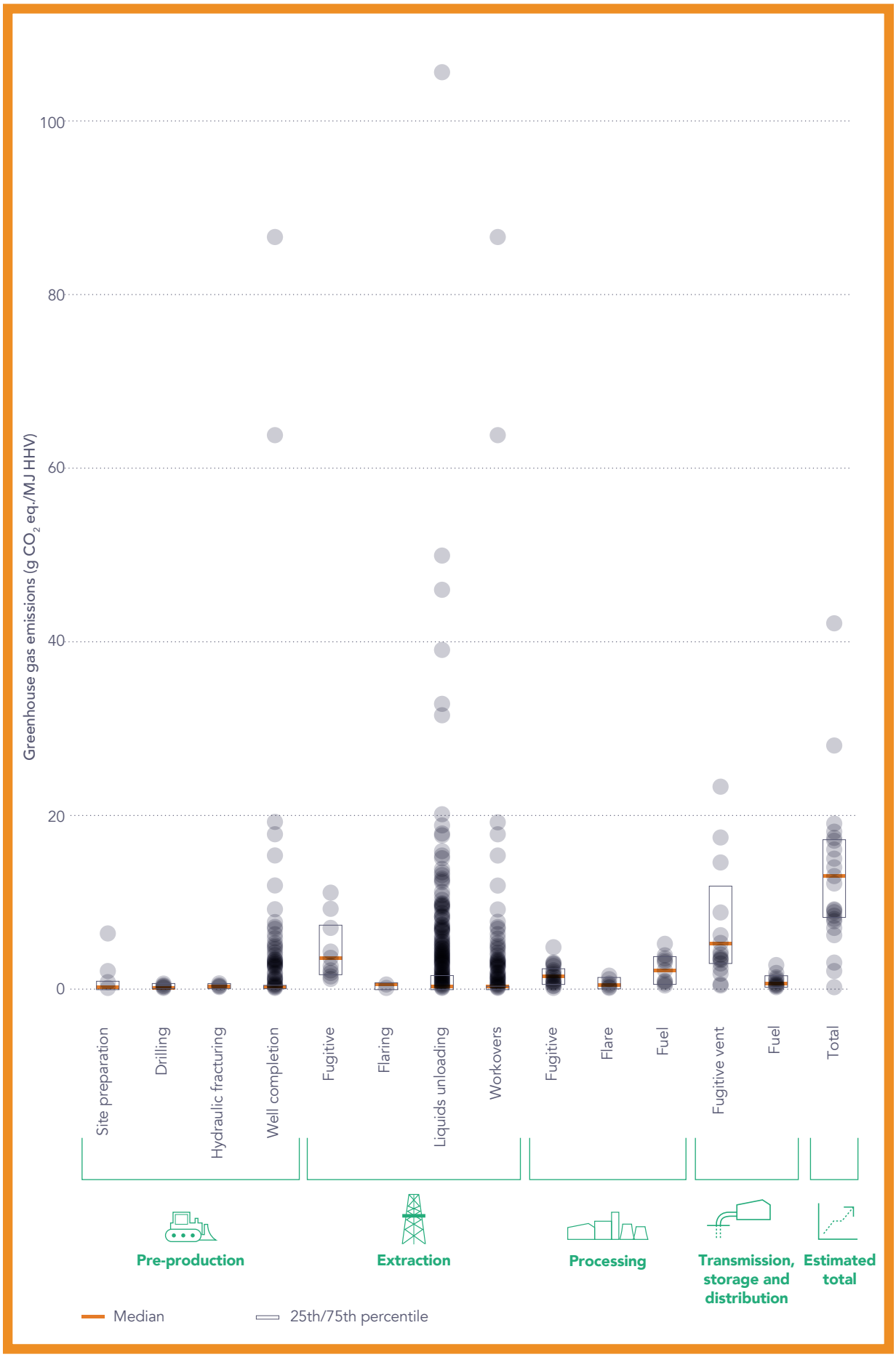
The range of emissions estimated at different sections of the supply chain, from extraction to distribution, is extremely large and is summarised in Figure 5 (opposite). Individual estimates at each stage of the supply chain are shown as grey circles, with the median (orange bar), 25th and 75th percentiles (black box) shown as horizontal bars. This range represents an aggregation of regions, well types and ages, geological formations, not to mention estimation methods and varying assumptions. Within this graph, it is apparent that there are three stages with some extremely large emissions estimates: well completions, liquids unloadings and workovers. Additionally, the median emission estimates across the data (represented as an orange line) lie towards the low end of the emissions scale for every supply chain stage, which suggests either a small number of facilities have extremely high emissions or that these estimates are erroneous. These aspects are described further within the following section, where emissions estimates from each supply chain stage are described, as well as the underlying data quality and representativeness.

FIGURE 5 (OPPOSITE) Greenhouse gas emission estimates across the natural gas supply chain
Each literature estimate of a supply chain stage is indicated as a grey circle. The median (orange), 25th percentile and 75th percentile (black box) estimate for each stage are shown with horizontal bars. Estimates of total supply chain emissions from individual studies are also shown.

3.1. Total supply chain emission estimates

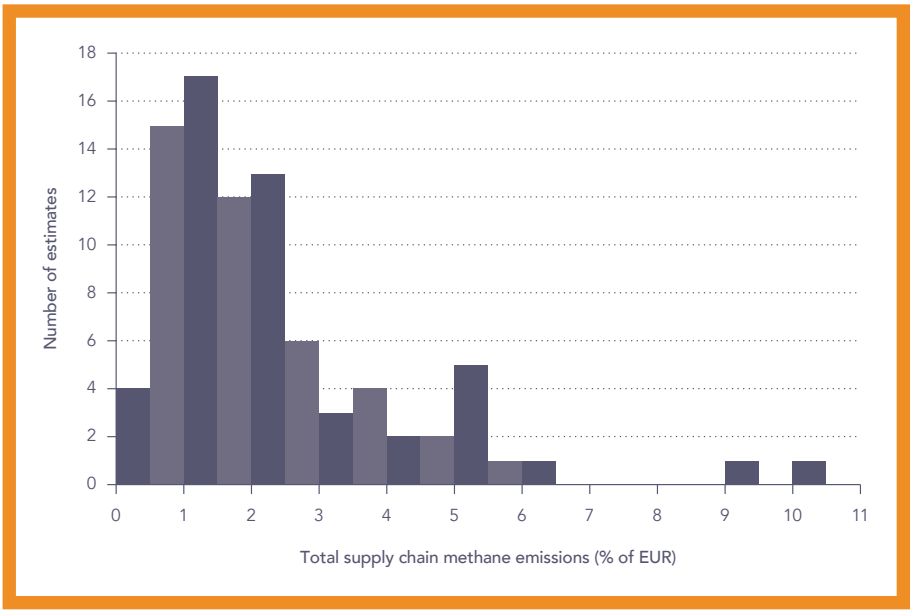
Estimates of total methane emissions across the whole supply chain ranged from 0.2% to 10% of produced methane[7]. The mean across the estimates was 2.2%, with a median of 1.6%. The highest estimates are generally acknowledged as being unlikely to be representative across large regions, but may occur for specific supply chain routes due to the varying quality of distribution pipelines and extraction processes. For example, Hayhoe [49] uses 10% as an upper limit but accepts that 2–4% methane loss is more likely. Similarly, Dedikov [50] summarises a series of estimates from various studies based in Russia, ranging from 1% to 10% and suggests the Russian average is

7. Produced methane is defined as the total quantity of methane extracted from the well.


Greenhouse gas emissions (g CO_2 eq./MJ HHV)
100
80
60
40
20
0
Site preparation
Drilling
Hydraulic fracturing
Well completion
Fugitive
Flaring
Liquids unloading
Workovers
Fugitive
Flare
Fuel
Fugitive vent
Fuel
Total
Pre-production
Extraction
Processing
Transmission, storage and distribution
Estimated total
Median
25th/75th percentile

closer to 1%. Figure 6 shows the distribution of estimates of supply chain methane emission across the literature studied. The figure shows that most estimates are in the range of 0.5–2.5%, as well as a small number of very high emission estimates, or a 'heavy tail'. This is a recurring theme within the literature and is discussed further in Section 4.2.5.

FIGURE 6
Histogram of literature estimates of total gas emissions from the whole supply chain [10, 16, 31, 32, 39, 49–63]
EUR = Estimated ultimate recovery of gas.



Many studies cite a range of emissions rather than a fixed volume, indicating the accepted variation across different supply chain routes and regions. High estimates are mostly around 4–5% of produced methane, middle estimates at 2–3% and low at 0.5–2% [10, 16, 31, 32, 39, 49–63].

Although this study does not address use-phase emissions (e.g. electricity generation), it is useful to frame the supply chain emissions within this context to demonstrate the relative contribution of the supply chain. For electricity generation, total life-cycle GHG emissions are normally estimated between 400 and 600 g CO_2 eq./ kWh of electricity generated [22, 31, 64–70]. Figure 7 shows the distribution of estimated total GHG emissions and again shows a heavy tail of larger estimates (note that some of this variation may come from different power plant emissions rather than upstream supply chain emissions). The power plant contribution to this is normally estimated to be around 400 g CO_2 eq./ kWh, often representing 70–80% of total GHG emissions.

Determining the contribution of total methane emissions to the total GHG emissions per kWh of electricity requires a number of assumptions, though it must be noted that this creates some uncertainty. Assuming that extracted gas is 80% methane by volume (and ignoring the contribution of the CO_2 content), a power plant thermal efficiency of 50% and a methane GWP100 characterisation factor of 34 (as per the most recent IPCC estimates), a methane emission of 2.2% of the produced methane is equivalent to 92 g CO_2 eq./ kWh, or 12.8 g CO_2 eq./ MJ of produced energy content (higher heating value, HHV). See Appendix A for the calculation method. This represents approximately 23% of the end-use combustion emissions (for

electricity generation) and over half of the upstream GHG emissions [17, 71]. Therefore methane emissions are a significantly large emission 'hotspot' along the supply chain.

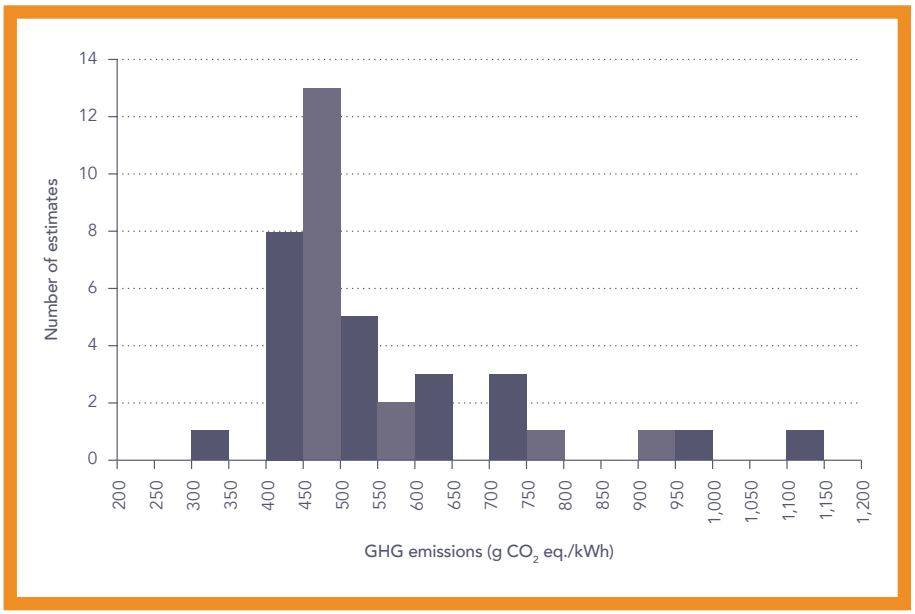


FIGURE 7
Histogram of estimates of life cycle greenhouse gas emissions associated with electricity generation from natural gas [22, 31, 64–70]

3.2. Pre-production emissions

3.2.1. Exploration

There is very little information on the emissions associated with exploration activities, such as seismic or magnetic surveying, initial drilling, core sample taking or initial hydraulic fracturing [19]. Emissions during this phase would be from energy use for equipment and transport, as well as perhaps a small quantity of gas release. Most studies of the natural gas supply chain either exclude this from the scope [e.g. 2, 15, 32, 72] or assume the emissions are negligible [e.g. 22].

3.2.2. Site preparation / construction

Estimated by Santoro et al. [73], CO_2 emissions from the energy required to prepare the site and the construction of the equipment represents approximately 1% of the natural gas combustion emissions across a well's life. Jiang et al. [72] also estimated that emissions associated with well pad preparation was very small, less than 0.2 g CO_2 eq./ MJ of produced natural gas. The energy requirements in operating the drilling equipment are similarly small [72], in comparison to other emissions such as the potential well completion emissions, described below.

Drilling energy requirements are slightly greater for unconventional well preparation as more horizontal drilling is undertaken. Likewise, the hydraulic fracturing process, which involves pumping large volumes of water at high pressure, will increase energy requirements for unconventional wells. However,

both these contributions to GHG emissions are minimal, with total pre-production emissions being estimated at around 0.2–0.9 g CO_2 eq./ MJ HHV, or 1.1–6.7 g CO_2 eq./ kWh electricity generated (using the calculation method in the Appendix) [19, 30, 66, 72–76], the vast majority of which are from CO_2. The well completions process however, which includes the flowback emissions from hydraulically fracturing, is not necessarily that small and is described below.

3.2.3. Well completions: A key emission

Unlike other pre-production estimates, the range of estimated well completion emissions is vast: from zero to 6,800,000 m^3 CH_4 vented per completion [3, 15, 16, 19, 20, 22, 25, 30, 54, 61, 66, 70, 72, 76–85]. Emissions are both from vented methane and CO_2 from flaring. The main sources of variation in these estimates are the well type, the equipment used for completion and whether the gas is vented, flared or collected.

Overall, there have been a large number of estimates of emissions from completion activities. All the estimates have been exclusively based in the US. There are measurements of onshore conventional wells, tight sands and shale gas, but no primary measurements of offshore conventional wells or CBM were found. The emissions for each well type are discussed below.

Firstly, it is important to note that the primary measured estimates of completions emissions are significantly different to modelled or secondary estimates. Table 1 illustrates the difference in estimates, in particular the difference between primary and secondary or modelled estimates. The large estimates from secondary/ modelled studies are largely due to a lack of knowledge of expected emissions: most of the studies included here were carried out prior to the publication of the primary measurement data. In fact these earlier studies [3, 54, 70, 72] were the motivation to take more primary measurements of these event emissions. Modelled emissions that are disproportionately large either use unsuitable or unverified data, or are modelled by assuming the gas flow rate is as high as the initial production rate, which is incorrect.

TABLE 1
Summary of methane emission estimates from well completions, split by conventional/ unconventional, primary/ secondary or modelled studies, and RECs/ Non-RECs [3, 15, 16, 19, 20, 22, 25, 30, 54, 61, 66, 70, 72, 76–85]
Emissions are measured in 1000s m^3 CH_4/ completion. Note that many volume estimates are at (American) standard conditions of 15.6°C and 1 atm, but some studies do not specify the conditions. REC: Reduced emission completions.

Well type	RECs	Data	Sample size	Emissions (1000 m^3 CH_4/ completion)			
				Mean	Median	Min	Max
Conventional		Primary	10	4.9	5.7	0.0	7.4
		Secondary	8	0.9	1.0	0.0	2.0
Unconventional	RECs	Primary	76	3.0	1.1	0.0	24.9
		Secondary	14	39.3	15.0	0.0	210.1
	Non-RECs	Primary	88	11.9	5.8	0.3	100.1
		Secondary	73	606.0	245.8	1.3	6800.0

There appears to be a broad consensus that conventional wells vent very little during well completion. Estimates of completion emissions for conventional wells are zero to 7,400 m^3 CH_4/completion [3, 15, 16, 20, 54, 78, 81, 84]. Given

that gas well total lifetime production estimates are generally between 10 and 1,000 million m^3, this represents less than 0.1% of total produced methane, less than 0.1 g CO_2 eq./ MJ HHV, or 1 g CO_2 eq./ kWh electricity generated. It is important to note however that no emissions data for offshore completion activities were found during this review.

For unconventional wells, however, the estimated range of emissions is much larger due to flowback emissions from the hydraulic fracturing process: zero to 6,800,000 m^3 per completion [3, 16, 19, 22, 51, 61, 66, 72, 86]. Coal bed methane wells are reported to have the lowest of unconventional well completion emissions, due to their comparatively lower well pressure when drilled [16, 87]. However, no measured data for CBM completion emissions were found, only estimates based on other unconventional well completions. Skone [16] suggests that tight gas wells tend to yield a smaller volume and are at a lower pressure, assuming emissions of 40% of that estimated for shale gas wells, at 104,000 m^3 per completion. Primary measurements of tight gas completion emissions are from zero to 60,400 m^3 CH_4 per completion [79], whereas secondary estimates of tight gas well completion emissions are between 100,000 and 710,000 m^3 CH_4 per completion [3, 15, 16, 78, 79, 84]. Primary measurements of shale gas completion emissions are zero to 537,000 m^3 CH_4 per completion [77–79]. Shale gas wells tend to exhibit higher pressure [16] and so will emit a higher flowrate of gas during completion. Secondary and modelled estimates again vary widely from zero to 6,800,000 m^3 per completion. The estimate of 6,800,000 m^3 per completion by Howarth et al. [3] is widely considered to be an outlying estimate [e.g. 22, 88]. The underlying source of this value could not be found but is discussed by Cathles et al. [88], suggesting that this is a calculated estimate assuming a flowback rate equal to the highest initial production rate, which does not happen as flowback gas flow rate is restricted by the entrained fluids [77]. This value should be excluded due to a lack of transparency of source data and excessive flow rate assumptions. The next highest estimates come from modelled estimates at approximately 1,000,000 m^3 CH_4 per completion [72, 85].

> When Reduced Emissions Completions (RECs) are employed and methane is flared to some degree, resultant CO_2 emissions from flaring may become significant.

Aside from the well type, the other main factor governing the magnitude of emissions is the type, or absence, of Reduced Emissions Completions (RECs). As can be seen by Table 1, the use of RECs reduces both the average event emissions and the variation in emissions significantly. This is discussed further in Section 4.2.1.

It is important to note that once RECs are employed and methane is flared to some degree, resultant CO_2 emissions from flaring may become significant. For example, the completion measurements by Allen et al. [77] included 13 sites (of 27) which flared methane, where CO_2 emissions from flaring accounted for 61% of GHG emissions (assuming a flaring efficiency of 98% and a GWP100 of 34 for methane).

3.3. Extraction emissions

During routine extraction operations, the largest GHG emissions are likely to be in the form of methane leaks and vents, as well as a small amount from combustion emissions. There are a few estimates of vented and fugitive methane emissions from operation of the well equipment, of less than 1% of produced methane [16, 30, 54, 75] and one of 1.9% [3]. Methane emissions are reported to occur from equipment leaks and vents, in particular from the use of gas-driven pneumatic controllers (these are discussed further in section 4.2.3). Methane emissions at this stage contribute 1–11 g CO_2 eq./ MJ HHV, or 8–80 g CO_2 eq./ kWh generated electricity. However, this does not include the liquids unloading process, which is discussed below. Estimates for extraction energy and flaring emissions generally lie between 0.1–0.5 g CO_2 eq./ MJ HHV, or 1 and 4 g CO_2 eq./ kWh electricity generated [30, 32, 54, 66, 73].

Skone [16] estimates that the GHG production emissions associated with offshore wells are less than half that of conventional onshore gas. This is due to the higher productivity rates from offshore wells, as well as the more stringent emission control measures in place for safety reasons [15]. Offshore gas wells that are selected for extraction must have greater production rates in order to be economically viable, as site production and construction costs are higher than for onshore wells. However, there was no primary GHG emissions measurement data found for offshore gas extraction.

As described in section 2.3.2, workovers may need to be carried out for unconventional wells during the well lifetime in order to re-stimulate the gas extraction flow rate. Estimates of emissions from re-completions, when accounted for, tend to be the same as the estimate for the original well completion [e.g. 87]. However the number of workovers required for a well varies significantly across a small body of literature. It is important to note that a workover may not include a re-completion, as a workover may consist of other operations as described in Section 2.3.2. Estimates are between 0.03 and 0.17 workovers per well per year [16, 20, 25, 87]. This higher figure of 0.17 is equivalent to one workover per well every 6 years, implying that relatively few, if any, workovers will be required during a well lifetime, considering that well lifespans are typically assumed to be 30 years. At such low workover rates, the associated emissions are likely to be insignificant. Workover rates vary across different well types, with API/ANGA survey results showing 0.3% for conventional and shale wells, 0.5% for CBM and 3% for tight sands [25]. The required workover rate depends on factors such as the initial pressure and porosity of the well, in addition to the liquids concentration and hydrates formation.

The accounting for gas gathering facility emissions, which occurs downstream of the extraction point but prior to processing, is inconsistent within the literature. Some studies mention gathering operations but do not detail emissions at this stage, whereas others do not account for gathering explicitly. There are very few primary estimates of gathering facility emissions, but one study suggests high variability in methane emissions [89]. Out of 109 gathering facilities, median emissions were 0.43% of throughput, which were typically

from liquid tank vents, leaking valves and pipes, dehydrator venting and compressor seal vents. CO_2 emissions are also likely not to be insignificant, due to the fuel usage for compressors and dehydrators [89], however no explicit accounting for this was found within the literature.

3.3.1. Liquids unloading: A key emission

The data on liquids unloading, although significantly improved over the past few years, is still lacking in depth and representativeness. All direct measurements come from the US and are either of limited sample size [51, 77] or are limited in transparency [78]. Emissions associated with liquids unloading are often unaccounted for in life cycle assessments [32] but may be a significant additional source of GHG emissions. Additionally, a number of studies incorrectly assume that liquids unloading is required for conventional gas but not shale gas [3, 15, 16, 30, 54, 70, 90] as this was originally assumed by the EPA [20].

Primary measurements of methane emissions from liquids unloading are between zero and 500,000 m^3 CH_4 per year [51, 77, 78], whereas secondary or modelled estimates range from zero to 38,000 m^3 CH_4 per year [3, 15, 16, 25, 32, 54, 61, 81]. These extremely large ranges vary due to the age of the well, physical characteristics of the well (such as the presence of liquids, pressure, size and permeability), the equipment and operating procedure used. As well as a large range of emissions per unloading event, the number of unloading events required per year varies considerably for different wells. This is illustrated within Figure 8, where the number of events per year range from zero to 7,500. The figure is shown on a logarithmic scale due to the sheer ranges of both events per year and emissions per event. It is important to note that the largest values of emissions per event are associated with lower number of events per year, and vice versa.

FIGURE 8
Primary measurements of liquids unloading emissions versus the number of events per year for each well [51, 77, 78]
Volumetric emissions are expressed at (American) standard conditions of 15.6°C and 1 atm. Note, for the GHGRP estimates, data points often represent more than one well. Data points are sorted by the reference source and the type of equipment used for unloading.

Figure 8 shows individual well emissions estimates from three sources: two from the University of Texas, Austin [51, 77] and one from the EPA GHG Reporting Program (GHGRP) [78]. The GHGRP is described in greater detail in Box 3, section 4.3. Whilst this source gives lots of data, the transparency and validity of measurement method is limited. The most comprehensive and transparent of these studies surveyed 107 different wells in many different basins in the US [51]. The sample was split into three categories: wells with a manually operated plunger lift; wells with an automated plunger lift; and wells with no plunger lift. Somewhat surprisingly, facilities with an automatic plunger lift emitted the most due to the higher frequency of unloading events. It is incorrect to assume that automated plunger lifts cause higher emissions, as this may be due to this equipment being installed on higher producing wells, or wells that require more frequent unloading events (e.g. greater water content). It is likely that the equipment used affects the level of emissions greatly, but this is not quantifiable with current data. The impact of equipment on emissions is discussed further in section 4.2.2. The average number of unloading events per year for manual plunger operations was 13, compared with 2,500 for automatic plunger unloading and 33 for operations without plunger lifts [51]. Shires and Lev-On [25] also estimated the number of vents per well per year by collecting data on 46,000 wells, finding wells with plunger lifts carried out 344 vents/yr whilst wells without plunger lifts carried out 32.6 vents/yr. However they did not specify whether the plunger lift was operated manually or automatically.

The annual volumetric emissions were similarly variable within the study by Allen et al. [51], with average annual emissions of 3,260 m^3 methane for manual plunger lifts, 28,600 m^3 for no plunger lift and 70,780 m^3 for automated plunger lifts. The total range across the sample was 28–552,100 m^3 methane per year [51].

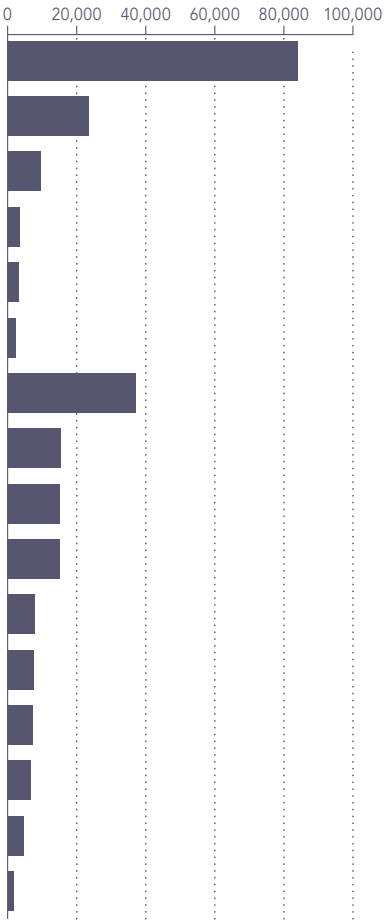
There is very little data on CO_2 emissions associated with liquids unloading. The only measured data found was for the GHGRP [78], suggesting that CO_2 emissions contribute less than 1% of total GHG emissions. However, there is little transparency in this dataset and it is unknown whether the CO_2 emissions are from the vented gas fraction or from flaring.

Additionally, data on unloading emissions are only for wells that either use plunger lifts or conduct blowdowns (indicated in Figure 8 by 'no plunger'). Evidently, emissions vary depending on the equipment used to unload, as shown in Figure 9. Although the wells with automated plunger lifts emitted the most, it is unlikely that the cause is technological. This is discussed further in section 4.2.2.

Whilst there appear to be some extremely large emitters, the distribution of emissions across the population of wells indicates that most wells are located at the lowest end of the scale. Wells do not require unloading during the early years of production. According to the API/ ANGA report [25], most wells require unloading at some point during their lifespan but 87% of these wells do not vent any gases whilst unloading. Allen et al. [51] find that the unloading frequency increases with well age, but it is unclear whether venting becomes more likely with increasing well age, or whether it depends on the physical characteristics of the well.

FIGURE 9
Methane emissions associated with liquids unloading from various primary and modelled literature sources [3, 15, 16, 25, 32, 51, 54, 61, 77, 78, 81]

Data	Reference	Plunger	Emissions/ event (m^3 CH_4)	Events/ year	Mean emissions per year (m^3 CH_4)
Primary	*Allen 2015 [51]*	Yes – Auto	34	2,445	
	Allen 2015 [51]	No	716	33	
	Allen 2013 [77]	No	1,616	6	
	Allen 2015 [51]	Yes – Manual	273	13	
	GHGRP 2015 [78]	Yes	27	120	
	GHGRP 2015 [78]	No	18	132	
Modelled	*ICF 2014 [81]*	Yes	-	-	
	Shires 2012 [25]	Yes	2	344	
	Shires 2012 [25]	No	58	33	
	ICF 2014 [81]	No	-	-	
	Burnham 2011 [54]	Mix	-	-	
	Venkatesh 2011 [61]	Mix	-	-	
	Shahriar 2014 [15]	Mix	489	31	
	Skone 2011 [16]	Mix	489	31	
	Howarth 2011 [3]	Mix	-	-	
	O'Donoughue 2014 [32]	Mix	-	-	



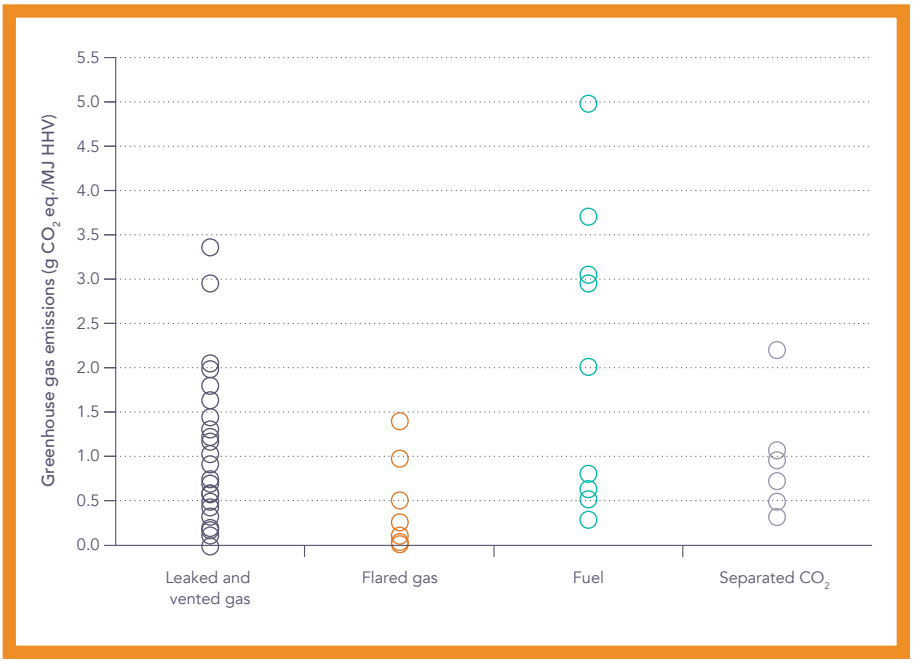
3.4. Processing emissions

Overall, there appears to be less uncertainty regarding GHG emissions associated with the processing stage, with respect to both methane and CO_2 emissions. However, there is still a large amount of variability, as is shown in Figure 10. Figure 10 illustrates the range of emissions associated with the processing stage. The main sources of variation come from fuel usage and fugitive methane. Total GHG emissions across the processing stage have been estimated as 1–13 g CO_2 eq./ MJ HHV, or 7–94 g CO_2 eq./ kWh of generated electricity [2, 3, 16, 19, 30, 31, 54, 66, 70, 73, 91, 92]. However, the available data is again heavily skewed towards the US [2, 3, 16, 30, 54, 66, 73, 83, 91, 92].

The main source of the magnitude of emissions is the combustion emissions from natural gas used as fuel. Equipment such as compressors and reboilers require natural gas combustion or electricity. Large ranges of energy demands are cited, from 0.5% to 9% of produced gas used as fuel [2, 16, 30]. Assuming an efficient combustion, this is equivalent to approximately 0.4–5.1 g CO_2 eq./ MJ HHV, or 2.5–37 g CO_2 eq./ kWh electricity generated. The energy requirement is dependent on the composition of the extracted natural gas (i.e. how much treatment is needed to produce the sales-worthy gas) and on the well pressure (i.e. how much compression is required to pressurise the gas).

However, there is little information on quantifying how much emission rates varied across different sets of gas compositions and pressures.

FIGURE 10
Life cycle greenhouse gas emissions associated with natural gas processing
Estimates of emissions are given for each of the following categories: leaked and vented gas (CH_4 emissions), flared gas (CO_2 emissions), fuel (CO_2 emissions) and separated CO_2. [2, 3, 16, 19, 30, 31, 54, 66, 70, 73, 91, 92].



Methane emissions tend to be measured as less than 0.5% of methane production, with an average across studies of 0.25% [2, 3, 16, 54, 89, 91, 92]. This is equivalent to 1.1 g CO_2 eq./ MJ HHV, or 7.6 g CO_2 eq./ kWh electricity generated, which is similar to the contribution of fuel emissions. Leakages are lower than at extraction facilities as processing facilities tend to be permanently manned, as opposed to extraction sites [89]. Of these methane emissions, the main sources are from liquid storage tank vents (flashing liquids), pneumatic valve venting and compressor and pipework flange leaks.

Another large source of GHG emissions has been reported to come from venting CO_2 during the CO_2 removal phase. The magnitude of emissions is dependent on the CO_2 content of the extracted gas and could contribute up to 50% of the processing GHG emissions for gas with a very high CO_2 content [54]. However, the potential for mitigation is limited without local CO_2 capture. A small amount of gas must be flared as well, typically less than 0.5% of produced gas [2, 16].

Perhaps the largest varying factor associated with methane emissions across different facilities is the age of the site. The documented gas emissions are typically leaks from more mature sites and there is a great distribution of site ages globally, with many being over 30 years old [91].

3.5. Transmission emissions

There is a limited range of emissions data on gas transmission, with the majority being centred on the US and Russia as these are the two largest gas producers in the world [93]. The combined production of these two countries accounts for 38.5% of the world total [93] and as a consequence they both have

an extensive gas transmission network comprising of 162,000 km of pipeline in Russia and 485,000 km in the US [94].

Typical emission sources associated with the transmission stage are CO_2 combustion emissions from natural gas fuelled compressors and methane leaks and vents from pipework, compressors and gas-driven pneumatic devices. Estimates for total methane leaks and vents across the transmission stage are between 0.05 and 4% of total produced methane [16, 30, 68, 70, 71, 82, 94–99], which is equivalent to 0.1–15.2 g CO_2 eq./ MJ HHV. However, estimates above 1.6% have used out of date or flawed estimation methods. For example, Howarth et al. [3] estimate that emissions for the US transmission, distribution and storage sector are 1.4–3.6%. This estimate is primarily based upon data measured by Lelieveld [95] for the Russian network [82] and includes distribution data taken from the EPA's 2002 annual inventory. Howarth et al. derive their overall upper estimate from 'lost and unaccounted for gas' in the state of Texas, a data source which is regarded by the EPA as flawed [100]. This is discussed further in Section 3.7. Additionally, Weber and Clavin's estimate [30] for the US transmission section of 0.8–2.2% is based upon a combination of Howarth's estimate [3] and the 1996 EPA/GRI data [101].

The most widely used data regarding methane leak and vent emissions from the US transmission network is still the US EPA GHG inventory [82], despite much of the emission factor data originating from the 1996 survey (described further in Box 2 in section 4.3). A summary of the EPA inventory emission and activity factors for the US transmission sector is shown in Table 2 and suggests that the largest source of methane emissions is from compressors.

However, as part of a series of studies conducted with the Environmental Defence Fund, emissions measurements across approximately a third of US transmission and storage facilities were taken [102]. The study involved primary data collection by a number of facility operators, as well as the aggregation of data from Subramanian et al. [103] and the GHGRP [78]. The study found that the emissions were not significantly different from those of the EPA GHG inventory, although the change in compressor types to dry seal centrifugal compressors across some of the network is likely to have reduced emissions. This is discussed further in Section 4.2.4.

	Activity Data		Emission Factor		Mg CH_4/year
Pipelines					
Leaks	489,900	km	0.027	m^3/ day/ km	3,310
Compressor Stations					
Station	1,807	Stations	248	m^3/ day/ station	111,200
Reciprocating Compressor	7,265	Compressors	430	m^3/ day/ compressor	774,800
Centrifugal Compressor (wet seals)	672	Compressors	1,422	m^3/ day/ compressor	236,700
Centrifugal Compressor (dry seals)	57	Compressors	912	m^3/ day/ compressor	12,880
Compressor Exhausts					
Engines	3.59E+13	MWhr	5.066	m^3/ MWhr	222,200
Turbines	8.57E+12	MWhr	0.211	m^3/ MWhr	2,209
Venting					
Pneumatic Devices	114,500	km	4,591	m^3/ year/ device	221,700
Pipeline Venting	489,900	km	895,880	m^3/ year/ mile	185,200
Station Venting	1,807	Stations	1.E+08	m^3/ year/ station	151,400
Total					**1,922,000**

TABLE 2
Methane emissions in 2012 for the US natural gas transmission sector [82]

The summary graph Figure 5 (see page 19) indicates that transmission, storage and distribution stages are considered to be significant contributors to supply chain emissions, whilst the EPA annual inventory data suggests that the transmission and storage sector contributes approximately one third of the natural gas industry's methane emissions [82]. The largest single emission sources are considered to be the blowdown valves and compressor seals, which are discussed further in Section 4.2.4. A collaborative study between the Wuppertal Institute, Ruhrgas, Gazprom and VNII Gas Institute [99] attempted to quantify the emissions from the Russian pipeline network and also found that the main source of emissions were compressor stations. As is consistent with many other methane emissions studies [103–105], they found that 0.5% of components accounted for 90% of the emissions. Venugopal [106] suggest that the age of compressor stations and level of maintenance has a significant effect on emissions, finding large variation across the sample compared to other studies [50, 99].

Numerous studies have identified methane emissions as being a complex issue primarily dependent upon maintenance practices [99, 103, 104, 107]. There are a number of methane emission mitigation measures that have been deployed by Gazprom over the past decade that have reduced Russian methane emissions significantly, many of which are similar to recommendations in the EPA's Natural Gas STAR Program [e.g. 82, 94, 106, 108]. Such measures include:

- **Forward line pumping:** For safety purposes, pipelines requiring repair have to be vented prior to maintenance work commencing. It is common practice to vent the gas directly to the atmosphere, resulting in significant emissions. Gazprom have found that portable compressors

can be used to pump the gas to a forward section of the pipeline, thus reducing vented emissions by up to 90% [94, 104].

- **Corrosion repair:** Composite wrap can be used to repair pipelines suffering from a minor defect. The wrap can prevent a defect such as mild surface corrosion from progressing to the point where the pipe must be isolated for repair [94]. This can save on downtime, direct repair costs and vented emissions.
- **Replacement of high-bleed pneumatic devices:** Devices operated by pipeline pressure can be replaced with either compressed air or low-bleed alternative designs [109].
- **Targeted inspection:** Directed inspection and maintenance programs can play a crucial role in reducing emissions [94, 108]. As the most likely leak sources are well known, targeted inspection programs can resolve leaks quickly and at low cost.

In addition to methane emissions, combustion emissions from compressors are also a key emission source for this stage. Both reciprocating and centrifugal compressors are mostly powered by gas taken from the transmission network that upon combustion produces carbon dioxide emissions [110]. Estimates of fuel usage for compressors are between 0.5% and 8.6% of total gas production [16, 30, 68, 70, 71, 97], which is equivalent to approximately 0.2–6 g CO_2 eq./MJ HHV. The quantity of emissions is governed by the transport distance required, as well as various technological characteristics. Transmission pipelines require compressor stations every 80 to 160 kilometres to replace pressure that is lost due to friction [98]. Average transport distances are often cited as approximately 1,000 km [16, 111], although this is highly variable across different networks and may be much more [96, 111].

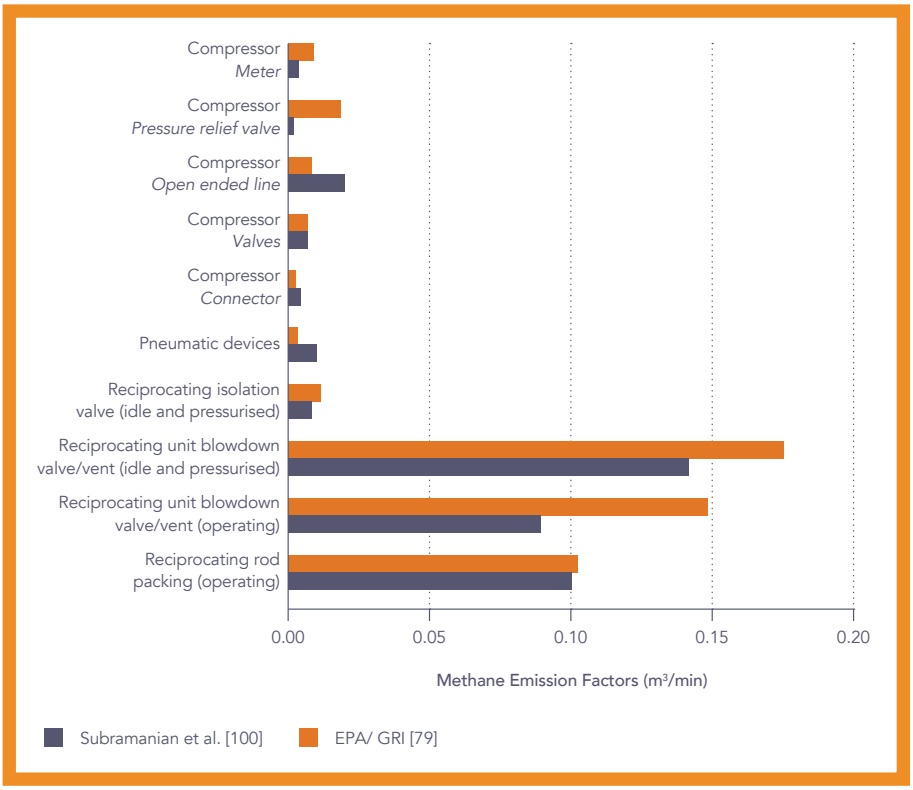
The GHGRP [112] estimates that in 2012, 22% of transmission emissions were from methane and 78% were from combustion CO_2 (using a GWP100 for methane of 34) [113]. However this estimate is likely to underestimate methane emissions as the reporting criteria excludes emissions from transmission lines between compressor stations. The EPA's annual greenhouse gas inventory [82] estimates that in 2012 carbon dioxide combustion emissions accounted for 52% of transmission, and 48% from methane leaks and vents.

3.6. Storage emissions

Storage facilities primarily comprise of compressors and dehydrator facilities [114]. As this equipment is also typically found within transmission networks, the EPA studies have tended to combine the two together [113, 115]. Both the EPA annual greenhouse gas inventory and GHGRP show that the main sources of storage methane emissions are from compressors. Storage compressors inject the gas into either underground storage reservoirs or back into the transmission network. The annual greenhouse gas inventory estimates that US compressor emissions total 212,591 Mg of methane per year, which is 43% of the total US methane storage emissions.

New estimates for storage emission factors have been recently made by Subramanian et al. based on measurements taken at nine underground storage facilities in the US [103]. A comparison between these and the original EPA/ GRI 1996 emission factors [see supplementary information in 103] is shown in Figure 11.

FIGURE 11
Comparison of storage emission factors derived from the Subramanian et al. [103] and 1996 EPA/ GRI studies [82], given in m^3/ min at 15.6°C and 1 atm

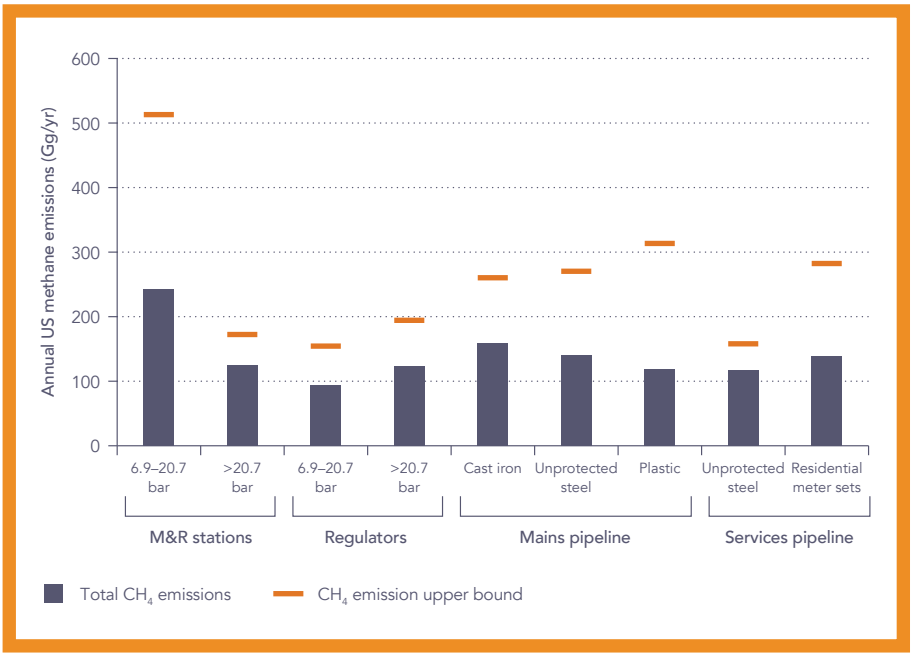


Subramanian et al. [103] suggest that the EPA emission factors generally overestimate the contribution from reciprocating compressor blowdown valves, pressure relief valves and compressor meters, whereas pneumatic devices and open-ended lines are underestimated. Additionally, Subramanian et al. [103] found that compressor venting was the most important category of emission, accounting on average for almost 50% of the site emissions measured by the study.

3.7. Distribution emissions

The distribution stage GHG emission estimates within the literature are from methane emissions only, in particular fugitive emissions at the Metering and Regulating (M&R) stations (city gate stations) and distribution pipelines [82]. Methane emissions from the US distribution system are estimated to be 20% of the US natural gas industry total [116]. Figure 12 shows the EPA emission factors for the nine highest methane emission sources in the US distribution sector [82]. A study by the Gas Technology Institute [117] (formerly the GRI) concluded that a large variation in these emissions was due to the wide distribution in data for this emission source. They suggest that the 1996 study had oversimplified the categories, resulting in widely varying M&R stations being combined into a single category.

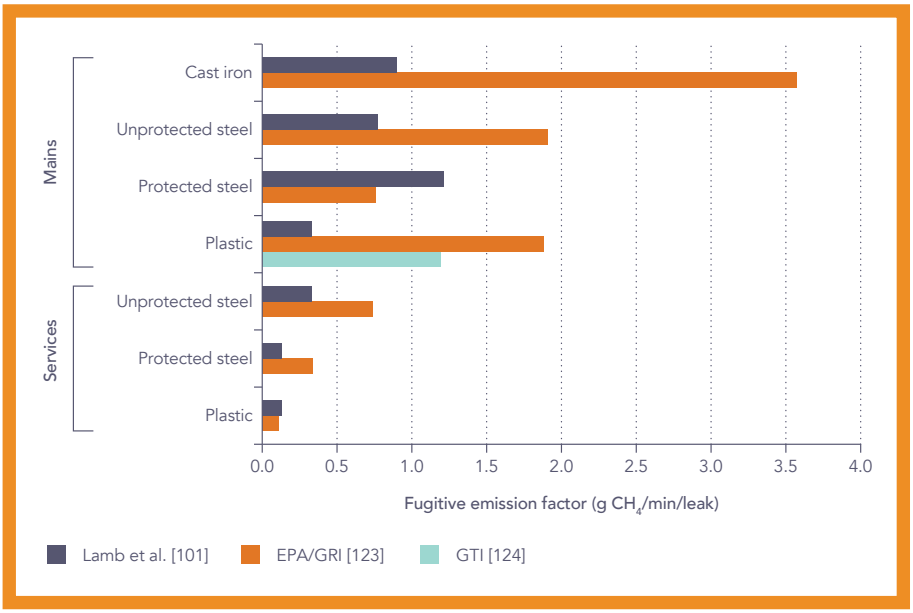
FIGURE 12
2012 total methane emissions and upper bounds for the nine largest methane emission sources for the US transmission and distribution sector [82]



A recent report by Lamb et al. [104] attempted to update the 1996 EPA/GRI estimates, particularly with regard to plastic pipeline emission factors. Their emission factors were nearly all lower than those reported in the original EPA/GRI study. For M&R stations they found that emissions were up to an order of magnitude lower, which they attribute to upgrades in equipment and maintenance protocols. Their updated emission factors suggest that overall methane emissions from the US distribution system are 393 Gg/ year. This is only 30% of the 1329 Gg/ year reported by the EPA in 2011 [118].

Three different studies [104, 119, 120] have estimated the methane emission factors for plastic mains pipelines, as shown in Figure 13. The large differences in estimation are due to several fundamental differences between the studies' methods and scope. The original EPA study was based upon only six measurements, whereas the Gas Technology Institute and Lamb et al. studies were based upon 22 and 23 measurements respectively. The EPA measurements were heavily skewed by five low values and one high value (0.003, 0.22, 0.36, 0.52, 3.29, 19.5 g/ min/ leak). Both the GTI and Lamb studies used surface measurements, whereas the EPA study excavated the pipeline to make a direct measurement and then applied a correction factor to account for the oxidation of methane by bacteria in the soil. The GTI also had a minimum detection limit of 0.19 g/ min/ leak, which was considerably higher than Lamb et al.'s 0.003 g/ min/ leak. This skewed the GTI's emission factor towards a higher value. If data below 0.19 g/ min/ leak is excluded from both studies, then the GTI's and Lamb et al.'s estimates are in closer agreement at 1.06 and 0.70 g/min/leak respectively [see supplementary information in 104]. Both the GTI and Lamb et al. studies agree that the original EPA emission factors overestimate the leakage rate from plastic mains pipelines.

FIGURE 13
Comparison of the emission factors from Lamb et al. (2015), GTI (2013), EPA/GRI (1996)



Several studies have attempted to measure the emissions in city distribution networks by continuously sampling whilst traversing across the city [121–123]. Studies in the cities of Boston and Washington had similar leak densities of 2.61 and 2.42 leaks per km of road, but with Washington having 51 leaks greater than the highest Boston leak of 28.6 ppm [121]. Greater emissions were from areas with more cast iron pipework [122], where unprotected metallic pipelines have high corrosion rates, which does not occur for plastic analogues. The EPA estimates that in 2012 approximately 10% of the US's 2 million kilometres of pipeline were made from either cast/wrought iron or unprotected steel [124]. In agreement with the EPA, these distribution leakage studies recommend that financial incentives should be put in place to encourage distribution companies to replace unprotected metallic pipelines.

Many early studies attempted to estimate leakage rates by measuring the difference between the gas produced at the well head and gas delivered to customers [125–127]. This is often termed as 'unaccounted for gas'. Leakage estimates using this method are large and range from 1 to 10% of production [115]. For example, Wallis [128] estimated in 1990 that the British Gas network was leaking between 3 and 10% of production, which was later refuted [129]. This is likely to significantly overestimate fugitive emissions as many other factors govern unaccounted for gas, such as unknown gas consumption by the transportation process, gas theft, unknown temperature gradients and faulty metering devices [130]. As a consequence of this, estimates since the mid-1990s have generally abandoned this method of leak estimation for more detailed 'bottom-up' estimates using emission and activity factors for individual components.

Elimination of unprotected metallic pipes is the most effective method of reducing emissions in this sector [82, 121, 122]. The EPA suggests that although the US gas distribution network has increased by approximately 500,000 km to 2,002,780 km in 2012 since 1990, the total emissions have decreased by 22.6% [82].

3.8. LNG emissions

Whilst there are several papers that attempt to calculate the emissions from liquefied natural gas (LNG) [6, 131–140], the literature is generally lacking in transparency and most of the source data used is not publically available. In particular, studies that estimate total supply chain GHG emissions tend to assume lower methane emissions than studies that do not incorporate LNG processes. The LNG stages consist of liquefaction, transportation by LNG tanker and finally regasification by heating the gas back to atmospheric temperature. Figure 14 shows an overview of the emission estimates by various authors for the different steps in this chain, with the largest contribution coming from the liquefaction process.

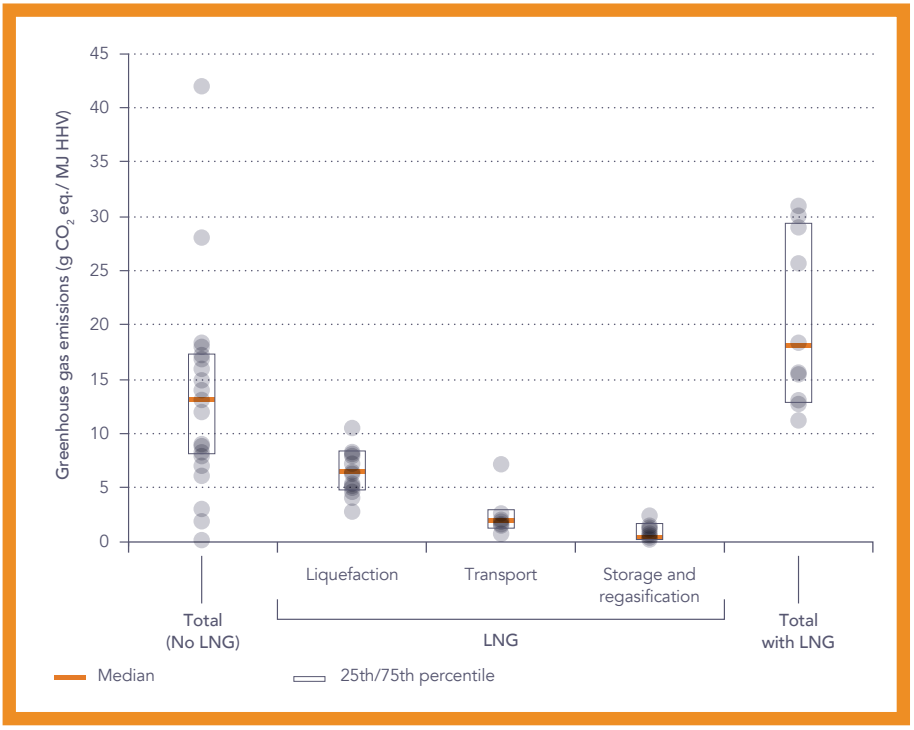


FIGURE 14 Overview of LNG emission estimates [6, 131–136, 138–140] for liquefaction, transport and storage and regasification stages
Estimates include CO_2 and methane emissions but with varying boundaries for each study. Also shown is the estimated total emissions from non-LNG supply chain, as previously shown in Figure 5. The median (orange) estimate for each stage are shown with horizontal bars. The 25th percentile and 75th percentile are shown as a black box.

3.8.1. Liquefaction

CO_2 emissions from the energy intensity of the liquefaction process is the largest contributor to LNG greenhouse gas emissions overall. The liquefaction energy demand is normally assumed to be 8–12% of the natural gas throughput, or from 4.09 to 7.66 g CO_2 eq./ MJ [6, 131–134, 140, 141]. It is normally assumed that natural gas is mostly used as the fuel for the liquefaction process, with diesel or electricity contributing a very small quantity (e.g. Choi and Song [134] assume 2% of energy is from electricity). Methane emission estimates from leaks and venting vary from 0.01 to 4.22 g CO_2 eq./MJ HHV [6, 132, 134–137]. However, there is limited transparency of the sources of these emissions and there is very little detail in particular on fugitive emissions.

3.8.2. Transportation emissions

The transportation emissions estimates for LNG are dominated by the CO_2 combustion emissions associated with propulsion of the LNG tankers. These emissions vary considerably depending upon the size, distance, efficiency and specific operating conditions of the tankers [142]. Emission factors have been estimated to vary between 9.4 and 14.4 g of CO_2/tonne-km by the International Maritime Organisation [143], with UK Department of Energy & Climate Change (DECC) [144] estimating 11.39 and Walsh & Bows [142] estimating 9.79 g of CO_2/tonne-km. Several authors have listed emission estimates as part of larger life cycle analyses, with the variation in values reflecting the chosen emission factor for the LNG tanker and the case specifics regarding origin and destination. Nie et al. [131] estimate the emissions for a 266,000 m^3 LNG tanker travelling from Qatar to the UK (11,400 km) as emitting 1.04 g of CO_2 eq./MJ. Masayuki and Atsushi [138] estimate that for an unspecified 10,000 km journey, 2.11 g of CO_2 eq./MJ is emitted. Often it is not specified whether the emissions associated with the return tanker journey is accounted for.

> Methane emissions associated with venting and leaks during transportation are generally poorly accounted for but may represent a significant proportion of the transportation GHG emissions.

Methane emissions associated with venting and leaks during transportation are generally poorly accounted for but may represent a significant proportion of the transportation GHG emissions: Choi and Song [134] suggest methane emissions could contribute between one third and two thirds of transportation GHG emissions. The main source of methane emissions is boil-off gas (BOG). LNG tankers store the liquefied gas in cryogenic containers that are not perfectly adiabatic, resulting in BOG that creates pressure within the tanker that must be mitigated. Boil-off rates during storage and shipping have been reported to be as high as 0.1–0.25% per day [133, 145]. This would have a significant emissions impact, but the recovery rate of BOG is estimated to be around 80%, and can be converted back to LNG or used as fuel for the tankers [134, 139]. Manufacturers of LNG tankers typically advertise boil-off rates of 0.25% per day, but it can actually go up to 75 days without having to vent any BOG [139]. As the vast majority of international LNG shipments take only a few days to reach their destination [46], emissions are likely to be low. Additionally, some port authorities have regulations that require all vented methane to be flared.

3.8.3. Regasification

Once LNG reaches its destination, it is stored, regasified and distributed. Overall, estimations for the regasification process represent a smaller contribution to the LNG supply chain, with values ranging 0.26–2.53 g CO_2 eq./MJ [6, 131, 133–136, 140, 146], mostly as a result of CO_2 combustion emissions for energy usage. It is typically assumed that 1.5% of natural gas throughput is required for fuel for the regasification processes [140, 146]. Minor variations

in estimates can be attributed to the differing sources of the LNG supplied to terminals, particularly with regard to the greater efficiency of the Middle Eastern liquefaction facilities. Cryogenic energy use is an option for energy efficiency gains, as waste heat can be used for industrial processes such as air separation [135]. Okamura et al. [135] suggest that such energy savings amounted to an emissions reduction of 0.29 g CO_2 eq./ MJ (i.e. the avoided burden of air separation emissions).

4. Why is the range of emission estimates so large?

As described in the previous section, the range of methane and CO_2 emission estimates across the literature is extremely large: individual supply chain sector estimates span orders of magnitude; total supply chain GHG emissions range from 0 to 42 g CO_2 eq./ MJ HHV, but the summation of the highest case individual stage emissions reaches over 300 g CO_2 eq./ MJ HHV; and total methane emissions estimates range from zero to 10% of the total extracted gas volume. This section analyses the data further to determine why this range is so large.

Key emission sources, as well as the potential technological mitigation of these emissions, in particular for well completions, liquids unloading, pneumatic devices, compressors and 'super emitters' are covered. Additionally, other factors affecting the wide range of emission estimates are discussed, including the distribution and lack of data, and the problems associated with the use of different estimation methods.

4.1. What is a realistic estimate of supply chain emissions?

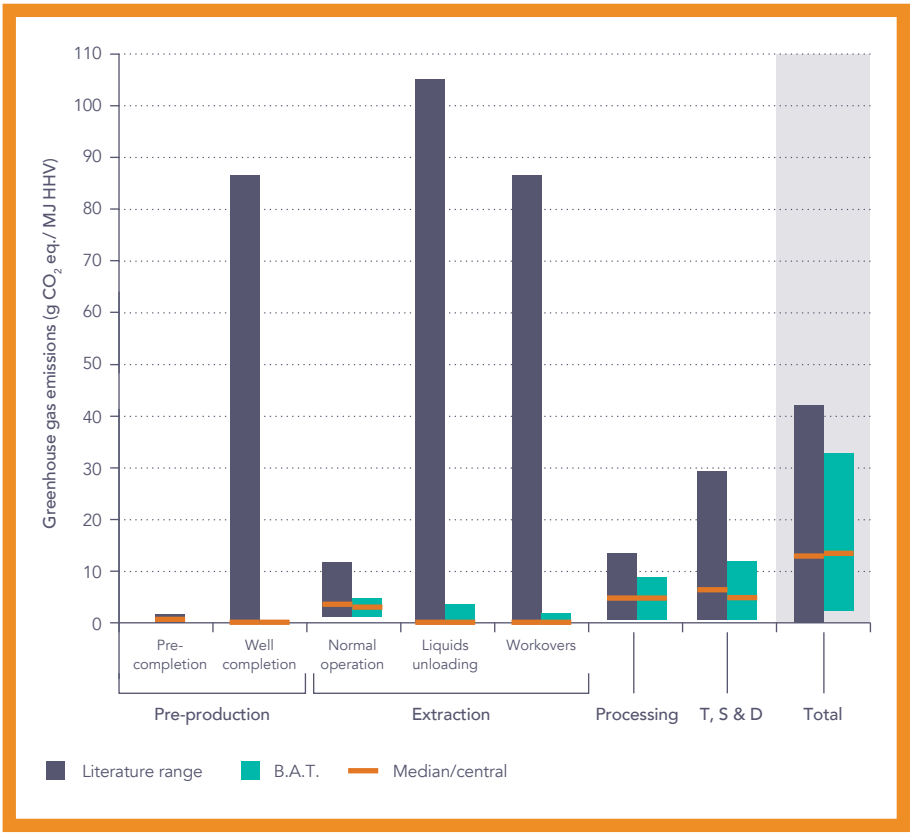


FIGURE 15
Greenhouse gas emissions across the natural gas supply chain for the literature values and a revised estimate, reflecting an effective operation during key supply chain stages, described as 'B.A.T.'
Low, high (green bar) and central (orange bar) estimates of emissions are given, based on the authors' judgement from the literature reviewed and accounting for Reduced Emissions Completions during well completion and workovers. Note, total literature estimates are not a summation of individual stage estimates but estimates of the whole supply chain only.

A reduced range of supply chain emissions has been created from the data in an attempt to represent the emissions associated with a modern well using current best practice technological operations, described here as 'Best Available Technique' (B.A.T.). Figure 15 shows such an estimate and compares this to the unmodified results from the literature. The justification for these revised estimates is described below.

For well completions, the high estimate was reduced significantly, from 86.6 to 0.3 g CO_2 eq./ MJ HHV. The new figures for minimum, central and maximum were based on the minimum, median and maximum emission from the primary measurements of completions using reduced emissions completions (RECs). Well completion emissions and the use of RECs is discussed further within section 4.2.1.

Emissions associated with normal operations during extraction (i.e. not during liquids unloading or workovers) have been lowered slightly from the aggregated literature figures: from 1.1, 3.8 and 11.5 g CO_2 eq./ MJ HHV to 1.1, 2.9 and 4.7 g CO_2 eq./ MJ HHV for minimum, central and maximum estimates respectively. The aggregated literature includes a number of estimates of methane leakage above 1% of total produced methane [3, 54]. The authors of this report judged the emissions range suggested by Weber and Clavin [30] of 0.2–0.8% (with a central estimate of 0.5%) to be representative of an achievable range using appropriate operation and maintenance procedures.

For liquids unloading, whilst the minimum (zero) and central (0.3 g CO_2 eq./ MJ HHV) are the same as the aggregated literature estimates, the maximum value has been reduced significantly (from 105 to 3.3 g CO_2 eq./ MJ HHV). The highest recorded emissions were from the paper by Allen et al. [51] for wells using an automated plunger lift. However, the magnitude of some of these emissions suggests that the unloading process may not be operated optimally (see section 4.2.2). Thus, these high emissions were assumed to be mitigable and the maximum liquids unloading emissions value was taken as highest emissions from the manual plunger lift dataset from Allen et al. [51]. This maximum emissions value under an effective operation represents a significant assumption that warrants further research. Liquids unloading emissions are discussed in greater detailed in section 4.2.2.

A reduced range of supply chain emissions has been created from the data to represent the emissions associated with a modern well using current best practice technological operations.

As the emissions associated with workovers are related to those from well completions, the workover estimates reduced similarly. The event emissions estimates are the same as for well completions, but the frequency of workovers has been reduced from the average estimate of 1.8 times per well life (of 30 years) to once per well life for the central estimate. This is comparable to more recent estimates of workover rates [25]. Some recent estimates of workovers are high (up to five workovers per well life) and vary for different reservoirs [25]. Consequently the high estimate assumes five workovers per well life.

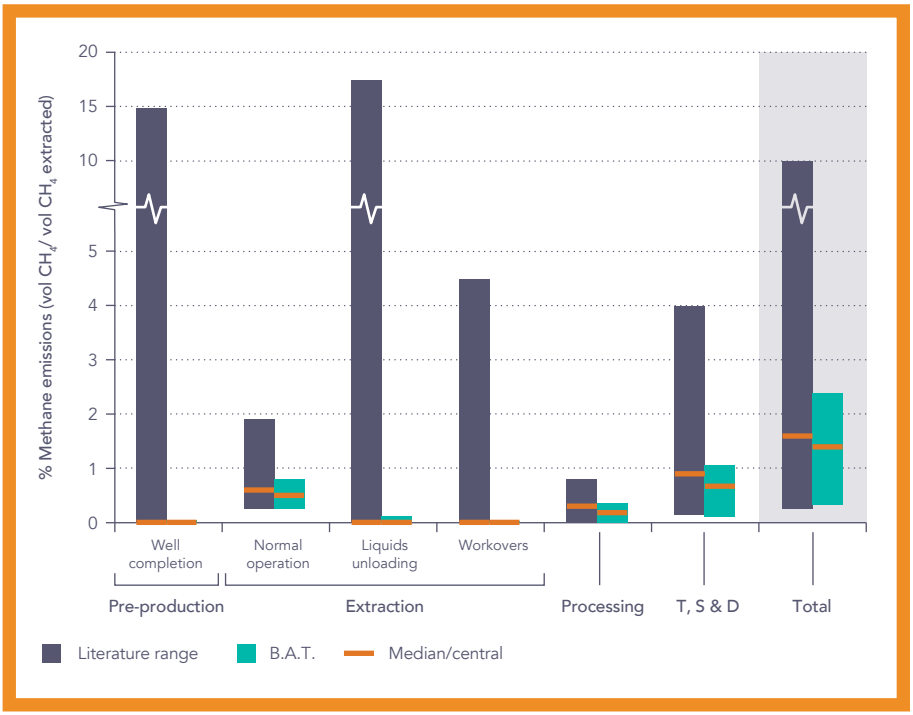
Emission estimates for the processing stage remained the same as the aggregated literature estimates for the low and central values. For the maximum value, the largest estimates of fugitive methane emissions (above 0.3% of produced methane) were assumed to be mitigable and are thus excluded from the revised estimate. Emissions associated with fuel usage and flaring emissions remain the same as for the aggregated literature.

Transmission, storage and distribution emissions consist largely of methane leaks and vents, and combustion emissions from compressor fuel. Whilst the estimates of compressor fuel emissions were kept the same for the revised estimate, methane leaks and vents were reduced significantly. As described in section 3.5 and 3.7, a number of studies used the 'lost and unaccounted for' method of estimating fugitive methane. These estimates were excluded to give a reduced range of 0.1%–1.1% of methane produced.

Overall, the anticipated range of methane and CO_2 emissions from an 'effectively operated' supply chain were between 2.7 and 32.8 g CO_2 eq./ MJ HHV, with a central estimate of 13.4 g CO_2 eq./ MJ HHV. Whilst the central estimate (13.4 g CO_2 eq./ MJ HHV) is close to the median estimate from the literature (13 g CO_2 eq./ MJ HHV), the range of values is significantly reduced from the current body of literature.

In order to place these figures into context, consider a scenario where the supplied natural gas is used for electricity generation in a combined cycle plant. Per kWh of electricity generated the supply chain emissions are equivalent to 19.4 (low), 96 (central) and 236 (high) g CO_2 eq./ kWh. Normally, power plant emissions are estimated to be approximately 400 g CO_2 eq./ kWh for this type. Therefore the contribution of the supply chain to total emissions (including electricity generation) would be 5%–37%. Within a future scenario, if Carbon Capture and Storage (CCS) was to reduce power plant emissions by, for example 80% [131, 147], the relative supply chain contribution would increase to between 19% and 75% of total GHG emissions.

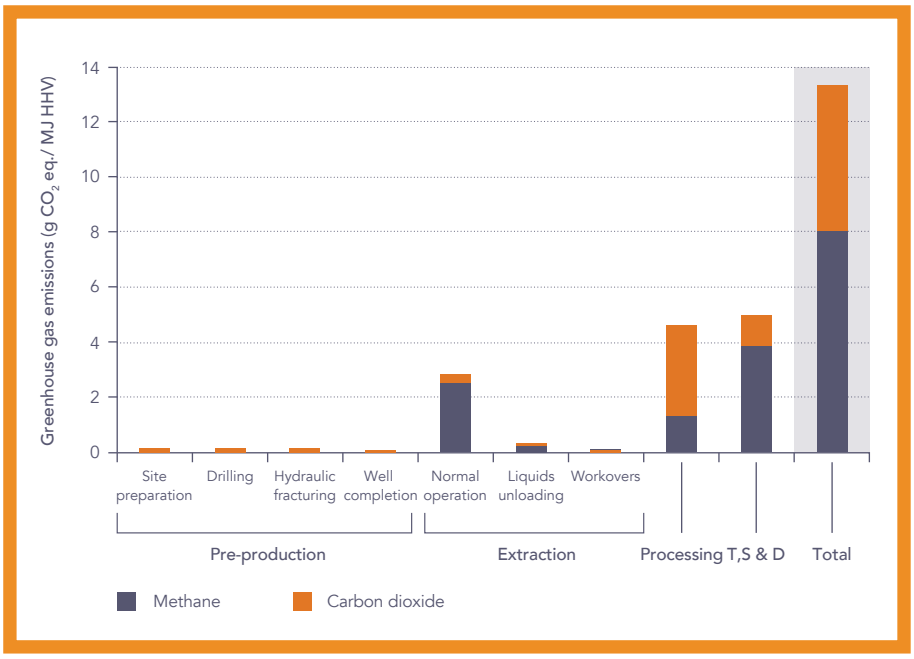
FIGURE 16
A summary of the revised estimates of methane emissions from fugitive and vented emissions, (described as 'B.A.T.'), compared to the aggregated literature estimates



It must be stressed that whilst data have been removed that were clear outliers or that did not use current best available techniques, the estimates of achievable fugitive methane emissions from some supply chain stages was based on the authors' judgement. However, the assumed total methane release represents a range of 0.28–2.4% (and a central estimate of 1.6%), which some may argue is still conservative. Figure 16 illustrates the assumed methane emissions (from both leaks and vents) used within the analysis and compares to the aggregated literature estimates.

Figure 17 presents the same central estimate as in the previous figure, but is split into contributions from methane and CO_2. Importantly, methane vents and leaks represent 60% of the total supply chain GHG emissions. Fugitive emissions from the extraction stage and the transmission and distribution stages are key contributors within the revised estimate and perhaps represent the greatest opportunity for emissions reduction. Indeed, this should be the target of further work: both in order to accurately estimate current emissions profiles and to identify pathways for minimising these emissions.

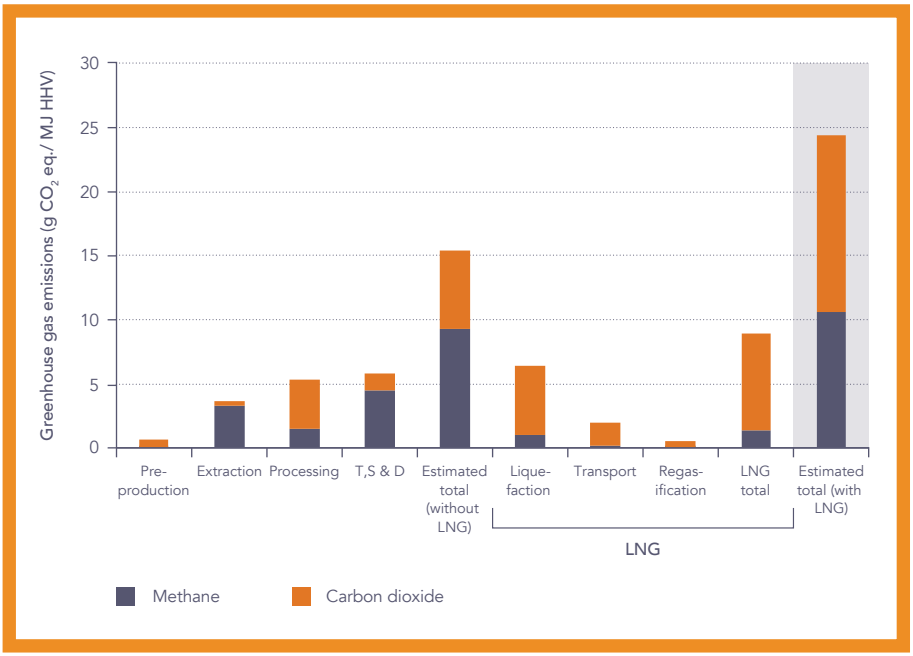
FIGURE 17
Revised central estimate of greenhouse gas emissions across the supply chain, split into methane and CO_2 emissions, reflecting an 'effective' operation during key supply chain stages
A value of 34 for GWP100 of methane is used. The category 'T, S & D' refers to the transmission, storage and distribution stages.



It is highly likely that emissions could be reduced further than these 'effective operation' estimates in the future. The identification of a potential emissions target for the natural gas supply chain is not within the scope of this report. Targeting emissions reductions is a complicated issue, both in terms of quantifying target emissions and also enacting upon or enforcing such targets. However, this could be the subject of further research, as such an estimate could contribute to further determining the potential role of gas in decarbonising global energy systems.

With regards to emissions associated with LNG supply chains, emissions were largely CO_2 combustion emissions from fuel usage, as can be seen in Figure 18. Whilst the literature sources may have underestimated the methane emissions as previously described, the revised estimates were kept the same as the literature values in the absence of more information. Note, in order to account for LNG supply chain emissions per MJ of delivered natural gas, the emissions from the rest of the supply chain stages increase slightly due to the greater gas 'loss' over the LNG stages. This is described in Appendix B.

FIGURE 18
Revised central estimate of greenhouse gas emissions across the supply chain with LNG, split into methane and CO_2 emissions, reflecting an 'effective' operation during key supply chain stages
A value of 34 for GWP100 of methane is used.



4.2. Key emission sources

As can be seen in Figure 16, the stages with the highest documented emissions are well completions (and workovers) and liquids unloading. Additionally, methane leaks and vents from compressors and pneumatic devices also appear to represent a significant proportion of supply chain emissions. These contribute to emissions across all stages of the supply chain. Another common finding across many emission measurement studies is the appearance of 'super emitters'. These are a small number of facilities across the supply chain that cause disproportionately large emissions. Each of these emission sources are discussed in greater detail within this section, with regard to the ranges of associated emissions, data availability and mitigation options.

4.2.1. Well completions

For the majority of studies that estimate a very high methane emission rate across the supply chain, well completions represent the largest portion [55]. This is often due either to large estimates from modelled emission rates, or not accounting for the use of Reduced Emission Completions (RECs).

Those studies that have not used primary data often base emission estimates on assumed initial gas production flow rates. For example, Bond et al. [75] assume that well completions last nine days and estimate flow rate using a production decline curve. The study produced two scenarios, assuming either 100% capture of produced gas or 100% flaring. They estimate emissions of between zero and 0.34 g CO_2 eq./ MJ of produced gas, assuming an EUR of 85 million m^3. However, the assumption of nine days of initial high production is an overestimate for the flow of gas. Using high initial production rates in this instance is not suitable because over the course of completion, the flowback rate will increase steadily from zero up to the production rate where the

well is then routed to the gathering lines [54, 77]. The assumption that gas is either 100% captured or 100% flared will result in an underestimate of well completion emissions: even with the use of RECs, an initial venting of gas often occurs while flow increases such that it is suitable to connect to the routing and collection equipment [77].

The use of RECs appears to have significantly reduced the anticipated emissions from unconventional wells, as was illustrated in Table 1. During the first years of unconventional well development in the US, the gas-liquid separators that were used during normal operation were not appropriately sized for the flowback rate and the solids concentration (sand from fracking fluid) and so the fluids were typically deposited in a pit or tank, whilst the gas was vented or flared [148]. As this process can take several weeks, the volume of emitted gas was large: a typical estimate is 700,000 m^3 per completion [148].

With the aim of reducing methane emissions, as well as other Volatile Organic Compounds (VOCs) and hazardous air pollutants, RECs equipment are now employed. This is a portable set of processing equipment where gas, liquids and solids are separated and the methane is captured and ultimately forms part of the sales gas [148]. Energised fracturing, which involves pumping CO_2 or nitrogen alongside the typical fracturing fluid, is sometimes used to increase initial production from a well. When this is carried out, additional separation equipment such as amine CO_2 absorption may be required in order to route gas to sales. If the gas cannot be directed to sales (e.g. due to low well pressure or gas composition), it may be captured and flared. The RECs process typically consists of differently sized gravity separators for sand, then liquids.

For the most established shale gas industry, in the US, the use of these processes is now compulsory, where estimates of emissions captured are 90–99% [17, 20, 55, 87]. Primary measurements of methane emissions from completions with these mitigation processes in place have been estimated at between zero and 25,000 m^3 per completion [16, 22, 54, 72, 75, 77]. Whilst this is an order of magnitude greater than the range for conventional wells (zero to 7,400 m^3 CH_4 recorded across the literature), this level of emissions represents a contribution of up to 0.3 g CO_2 eq./ MJ HHV, or 2.3 g CO_2 eq./ kWh of electricity generated (assuming a EUR of 57 million m^3, 50% power plant thermal efficiency, for a GWP100 value of 34 g CO_2/ g CH_4). This should make unconventional well emissions comparable to those of conventional wells, because the downstream processes are similar [22].

Thus, the vented natural gas emissions from flowback, or well completion in general, are likely to be insignificant, due to the use of RECs. For the revised estimate of the range of completions as shown in Figure 15, the minimum (0 m^3 CH_4 per completion), median (3,000 m^3) and maximum (25,000 m^3) values from the primary data sources of wells using RECs were included [77, 78], as this represents best practice.

4.2.2. Liquids unloading

The range of estimated emissions from liquids unloading is extremely large, spanning several orders of magnitude. Whilst there may be no single

representative study of this supply chain stage, it appears that this is a good indication of the scale of the overall range. However, there is very little (documented) understanding of how and why emissions vary across different wells in different regions at different stages of their lifespan. Most wells do not require liquids unloading in the early years of production and according to American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA), 87% of wells do no vent whilst unloading. However, this figure represents a cross-section of wells in 2012 and consequently the impact of well age on vent rates during unloading is unknown. Further research is required to develop a sound understanding of the factors affecting unloading emissions across the life span of a well.

> The range of estimated emissions from liquids unloading is extremely large, spanning several orders of magnitude.

The main mitigating measure recognised within the literature is the use of a plunger lift to conduct unloading. According to the API/ ANGA report [25], 36% of US gas wells have a plunger lift installed. However, there is no indication of the proportion of different equipment types used globally.

ICF International estimated that plunger lifts reduce emissions by 95% compared to blowdown operations [81], but give no justification for this figure. According to Smith [149], plunger lifts do not inherently reduce or eliminate venting emissions, which instead requires an understanding of the reservoir energy, pressure differences and the specific equipment used. If there is insufficient pressure differential to allow the plunger to rise to the top, the well must be vented to atmosphere (to remove the back pressure) to complete the cycle. The pressure differential depends on the reservoir pressure, the height of liquid head pressure and the back pressure from the process separation and gathering equipment [150]. The API/ ANGA report [25] suggests that 21% of wells with plunger lifts vent during an unloading cycle. In comparison, only 9% of wells without plunger lifts vent during unloading [25].

Plunger lifts with high emissions are likely not to be operated efficiently according to Alvarez et al. [150]. ICF International [81] also point out that if the vent remains open once the flow rate increases to maximum (once liquids have been discharged), this would result in a very high emission, potentially exceeding emissions from non-plunger lift wells. Instead, the operation of a plunger lift can be automated with a set of controlling and optimisation equipment, using well characteristics and operational experience to control the unloading frequency and duration.

Alvarez et al. [150] estimate that automated plunger lift operations can reduce emissions by more than 99% from high emission plunger lift wells, citing a presentation given by BP on 'smart automation' for the Natural Gas STAR program [151]. BP suggest that unloading vent emissions from their 2,300 San Juan basin wells have reduced from over 110,000,000 m^3/yr in 2000 to less than 300,000 m^3/yr in 2010 by applying smart automation on wells both with and without plunger lifts (50/50 split), using the experience of operating

plunger lifts and changing the operational philosophy with venting being the last resort. An important note is that their approach required adaptation for different well and reservoir characteristics: this case study emissions reduction took over 10 years to achieve. As is evident from the emissions data collected by Allen et al. [51], the use of automated plunger lifts does not necessarily guarantee low emissions. Thus, whilst plunger lifts are likely to reduce the venting time and volume, such emission reduction is not guaranteed without effective operation.

For wells where plunger lifts are not feasible, a 'smart automation' of unloading blowdown operations would also reduce emissions, minimising blowdown times and optimising the frequency and duration of well shut-ins [149].

Where venting is necessary, it has been suggested that the EPA should consider requiring operators to use gas capturing systems [152]. However, gas capturing systems similar to RECs for well completions may not be feasible due to the need for a high enough differential pressure. It has been suggested that a mobile flaring system may be used for the vented unloading emissions [150], but Bolander [153] asserts that such a system would not be cost-effective due to the high, and highly variable, gas flow rate with associated high design costs.

Other than the use of plunger lifts, there are a large number of other operations that can be carried out to unload liquids. As well as plunger lifts, velocity tubing, intermitting and soap injection all use the reservoir energy to conduct unloading. Alternatively, down-hole pumps to create artificial lift (of liquids) and gas lift systems add energy to increase flow [153]. Compressors may also be added close to the extraction point to reduce back pressure.

Indeed, API/ ANGA report that 13% of US gas wells use artificial lift equipment [25]. This is notable as they state that this negates the requirement for liquids unloading, thus avoiding this emission source. However, no source data on the emissions characteristics of any of these other process operations were found within the literature. Therefore further research is required in order to determine the frequency of use of these processes and their likely associated emissions.

In summary, it is clear that further research is required for the following:

- Determining the distribution of unloading requirements across wells and the factors affecting this distribution.
- The use of a mean or average emissions per well estimate has the potential to create significant error due to the skewed distribution of emissions across different wells. More direct measurement of this variation is required, alongside a causal analysis of the emissions relating to geographical qualities, equipment, operation and regulation.

- Determining the effectiveness of different unloading techniques in order to understand how unloading emissions can be minimised. In particular, there needs to be a better understanding of plunger lift control practices, in order to determine the causes and environmental effects of differing venting control [24, 25]. Wells with no mitigation technologies and those with high emitting plunger lift operations should also be the subject of emission reduction measures [150].

For the revised estimate of the range of unloading emissions as shown in Figure 15, the minimum estimate is zero and the median estimate represents the median value from the primary data sources (1,400 m^3 CH_4 per year) [51, 78]. The maximum value used was the maximum from the manual plunger lift data (17,500 m^3 CH_4 per year) [51]. In order to estimate levelised GHG emissions per MJ HHV, it was assumed that these emissions occur for half of the lifespan of the well, as no other data was available. Varying this assumption may have a significant impact on the life cycle GHG emissions, but there is little data on when liquids unloading is required. This should be the subject of further research in order to gain a more accurate determination of unloading GHG emissions.

4.2.3. Pneumatic devices

The EPA reports that methane emissions from pneumatic devices contribute 14% of the annual supply chain methane emissions [82]. This is likely to be even greater as the reports only account for pneumatics at the extraction and transmission stages within their assessment (i.e. not accounting for the processing stage). However, estimates of emissions have been largely based on emission measurements conducted as part of the EPA/ GRI 1996 survey [154]. Recently, three additional pneumatic emission studies have been carried out which have furthered our understanding of this emission source [77, 155, 156].

At all stages of the supply chain, pneumatic devices are used to control or measure flow rates, temperatures, liquid levels or pumping systems. Pneumatic controllers use a pressurised gas to create a mechanical movement for the operation of valves, instruments and pumps. Within the natural gas sector it is typical to use the pressurised natural gas for this purpose. For example, pressure control valves can use the energy contained in the gas to force open a spring mounted diaphragm to control the pressure of a fluid. Although these devices typically vent small amounts of gas, the large number of devices that exist throughout the natural gas supply chain means that their overall contribution is large. Industries other than the natural gas sector tend to use instrument air systems instead of natural gas for pneumatic controllers, using compressed and filtered air.

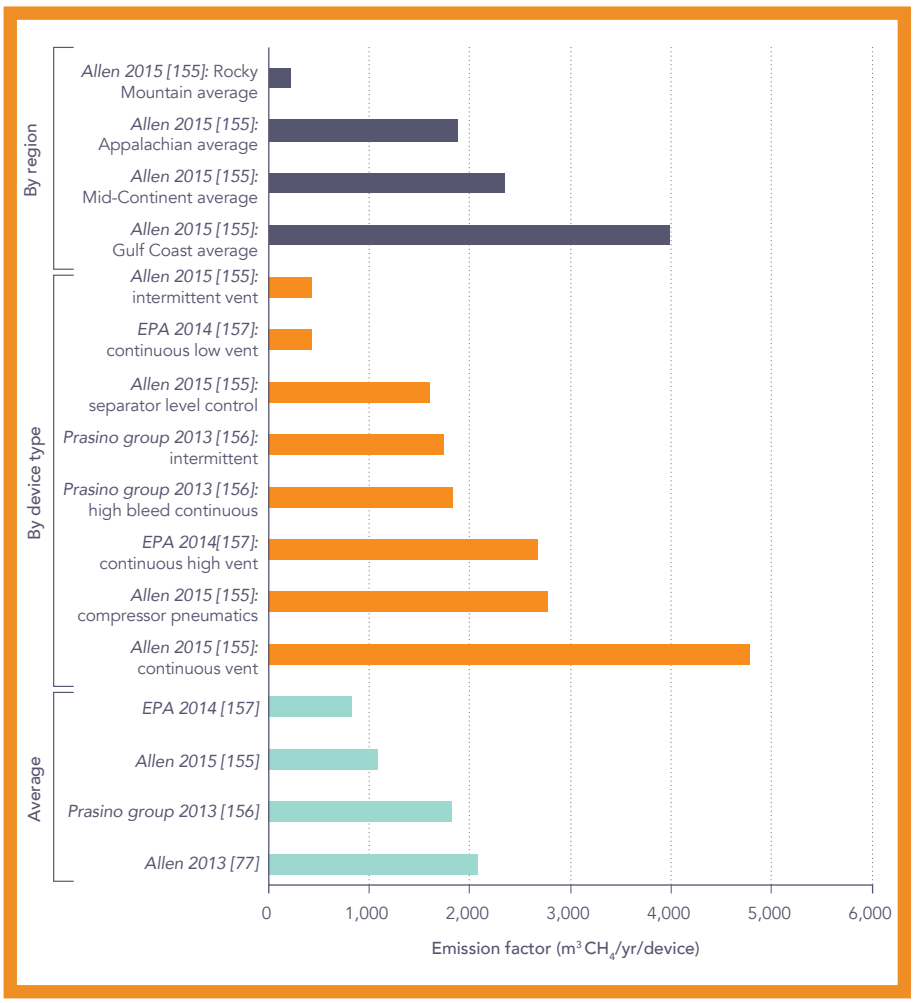
Pneumatic devices normally vent gas by design due to the driving force being the pressure differential between the gas and the atmosphere. Two types of pneumatic device are continuous and intermittent vents. Continuous pneumatic controllers are used to regulate process conditions (e.g. pressure) and are often characterised as high-bleed or low-bleed types (less than 0.17 m^3/hr) [157]. Intermittent pneumatic controllers vent intermittently and are used as actuators to open and close devices such as valves. There are also zero-

bleed pneumatic controllers, which are self-contained and feed vent gas back into the process lines [157]. These can only be used in systems operating under a low pressure and thus are atypical of the gas sector.

Figure 19 summarises the four sources of measured data found within the literature and illustrates the large range of emission rates across regions, supply chain stages and types of device. In terms of magnitude, the exhibited emissions are similar to those from liquids unloading vents. The greatest variation appears to occur across the different types of pneumatic devices. In particular, continuous vent pneumatics emit more than intermittent devices. There is also significant regional variation, even though the regions studied were all within the US. This may be due to a greater use of continuous vents rather than intermittent vents, or due to the greater frequency of actuation of the devices for certain basins, for example on liquid level controllers for wells that produce high quantities of liquids [155]. Allen et al. [155] reported that there was significant variation within each category and suggests again that relatively few devices (19%) caused the vast majority (95%) of emissions. Many of the highest emitting devices were not operating as designed, suggesting that they were defective. It has also been reported [157] that older or less well maintained controllers vent more gas than well-maintained controllers by approximately 0.14–0.28 m^3/h. Consequently an appropriate inspection and maintenance regime is required to minimise emissions.

Other measures to reduce these emissions are to replace continuous bleed devices with zero-emission devices where the operating pressure is low enough, or to use instrument air as the pneumatic driver. Instrument air systems are dedicated processes which provide filtered and pressurised air flow to pneumatic devices. However, this would require the installation of an additional compressor, filter and condensate knock-out pot, which represents an additional environmental and economic cost. The financial feasibility of such a system depends on the number of pneumatic devices and on the potential emissions reduction.

FIGURE 19
Annual estimated emission factors for pneumatic devices from primary sources, aggregated by region and device type



This report has not attempted to estimate levelised emissions from pneumatics due to the uncertainty of assumptions that would be made: the number of pneumatic devices across the supply chain must be estimated and allocated to each well, which would require system modelling and is outside the scope of this review. Estimates of the number of pneumatic controllers used at the well site is 1–3.6 [81, 155, 157], whereas gathering and boosting stations may have more [81]. There are relatively few at processing facilities (where instrument air is more often used), but there are more along the transmission stage (no data was found for either). However, all stages downstream of the well site incorporate flow from many wells, thus emissions must be allocated by the total throughput of the downstream process. No studies were found that analyse the contribution of pneumatic devices to the life cycle emissions of a natural gas well and this should be subject of further research.

4.2.4. Compressors

Compressors may be used at all stages of the natural gas supply chain: extracting gas from low pressure wells, equalising pressure within gathering lines, increasing pressure at processing facilities and driving the gas through

the transmission and distribution lines [158]. Compressors were reported to be responsible for almost 20% of natural gas supply chain methane emissions in the US in 2012 [82]. Emissions from compressors tend to occur through vented seals or compressor blowdowns [159]. Blowdowns are the release of gas from the offline compressor to the atmosphere.

The two main types of gas compressor used in the natural gas sector are reciprocating and centrifugal compressors. Reciprocating compressors are known as 'positive displacement' compressors and are driven by a piston, directly compressing gas within a cylinder. The rod which connects the driver to the piston needs to seal the gas from the outside environment using rod packing, which is the cause of most leaks from this system [158]. Centrifugal compressors drive an impellor which pressurises the gas like a centrifuge. In this case the seal must be around the rotating shaft which drives the impellor. The seal may be either a wet seal, using an oil circulation unit at high pressure, or a dry seal where pressurised springs provide separation from the outside environment. The oil in wet seals tends to entrain gas which is vented from the system [158].

Subramanian et al. [103] undertook measurements at 36 transmission compressor stations and nine underground storage compressor stations for centrifugal and reciprocating compressor blowdown and seal vents across the US. The data shows the wide variation in emission factors that can occur when the specific details of the compressor operation are taken into account and thus highlights the potential for error that can occur when extrapolating emission factors that do not capture the complexity of real operations. Both the Subramanian et al. [103] and Harrison et al. [159] studies found that the emissions from centrifugal compressor wet seals and reciprocating compressor rod packing are greatly underestimated in the original EPA/ GRI study. The 1996 EPA/ GRI study [154] measured the emissions from compressors over a relatively short period of time and then extrapolated those emissions over the course of a year. However, this is an oversimplification as compressors are routinely cycled in and out of operation in response to varying demand loads and maintenance requirements. At any time a compressor will be in one of the following three modes: operational, idle and pressurised, idle and depressurised. Harrison et al. [159] took methane emissions measurements from the vent lines on idle and depressurised reciprocating compressors and found them to be a significant source of emissions, although the cause of this is not clear. Some compressor stations are designed to have multiple emission point sources venting to shared lines. This makes separation of emissions from compressors in differing operating modes impossible without reconfiguring the design of the compressor station.

TABLE 3
Comparison of compressor emission factors from Subramanian et al. [103], Harrison et al. [159] and the EPA/GRI [154]

Emission Source	Subramanian et al. 2015 (m^3/min)	Harrison et al. 2011 (m^3/min)	EPA/GRI 1996 (m^3/min)
Centrifugal compressors			
Blowdown vent operating	0.153	0.004	0.504
Blowdown vent operating + idle	–	0.085	
Wet seal (operating)	0.747	0.438	0.009
Reciprocating compressors			
Blowdown vent (pressurised + idle)	0.008	0.105	0.198
Blowdown vent + Pressure relief valve (operating)	0.192	0.458	
Blowdown vent + Pressure relief valve (idle and depressurised)	–	0.850	
Rod packing (pressurised + idle)	0.088	0.659	0.021
Rod packing (operating)	0.125	1.594	

The study by Subramanian et al. also noted two 'super emitters', both of which were inactive stations on standby mode. As is very common in leak detection studies [105], the two super emitters skewed the results so that the highest emitting 10% of sites were responsible for over 50% of the emissions. Subramanian et al. compared their results to the EPA's Greenhouse Gas Reporting Program (GHGRP) [113]. The GHGRP uses an emission factor for unburned methane in the exhaust gases of reciprocating compressors of 0.023 m^3/min. They found this to be a large underestimation, with the true value likely to be closer to the EPA's air pollutants estimate of 12.8 m^3/min [105]. Several emission factors for leaking components were also found to be outdated, in particular open-ended compressor lines were found to have an emission factor of 0.048 m^3/min, compared to the GHGRP value of 0.008 m^3/minute.

Centrifugal compressors have been found to have lower methane emissions on a power-to-power basis than reciprocating compressors [103]. Venting rates tend to increase as compressor components degrade [158]. Thus, inspection and maintenance procedures are vital in maintaining low leakage rates. Centrifugal compressor emissions can be minimised by replacing wet seals with dry seals, or by capturing the wet seal gas emissions [158]. Dry seals provide reduced leakage rates and are also more effective in reducing drag on the moving parts and thus produce a more efficient compressor, requiring less maintenance. The continuous circulation of oil in wet seals can demand 50 to 100 kW of power, whereas dry systems are in the range of 5 kW. However, it should be noted that there have been reports of dry seals with leak rates that are only slightly lower than wet seals, though why they are leaking is presently unclear.

The presence of 'super emitters' within the natural gas supply chain has been identified frequently within the literature, particularly within the last four years.

An alternative to wet seal replacement is the incorporation of a gas separation chamber to capture the gas as it is released from the seal oil and feed it into the compressor fuel gas line. This can be a simpler and more cost effective strategy in many situations [158].

Reciprocating compressor emissions can be minimised by regular replacement of rod packing [158]. A new rod packing system may emit 0.3 m^3/ hour per compressor. The highest emitting rod packing recorded by the EPA was up to 25.5 m^3/ hour. The reduction in emissions is dependent on the rate of degradation of the packing and the frequency of replacement.

For both types of compressor, leakage rates have been found to be proportional to age [160], with a vast distribution of ages across different transmission networks in particular: Stanek and Bialecki [160] find that 17% of transmission compressors in Poland are older than 35 years.

4.2.5. Super emitters

The presence of 'super emitters' within the natural gas supply chain has been identified frequently within the literature, particularly within the last 4 years. The super emitters are a small number of facilities within the supply chain that emit disproportionately large amounts [105, 161]. They are responsible for increasing the greenhouse gas emissions of the whole sector and potentially skewing the average emission factors associated with each supply chain stage. Table 4 provides a range of example studies where evidence of super emitters has been found.

TABLE 4
Evidence of super emitters across the supply chain, sorted by supply chain stage

Reference	Stage	Region	Description
ERG 2011 [162]	Extraction	US	10% of gas wells emitted 70% of fugitive methane emissions.
Allen 2015 [51]	Liquids unloading	US	20% of wells with plunger lifts that vent account for 70% of plunger venting emissions.
Shires 2012 [25]	Liquids unloading	US	10% of total well population account for over 50% of liquids unloading emissions.
Shires 2012 [25]	Liquids unloading	US	3% of wells without plunger lifts account for over 90% of no-plunger unloading emissions.
GHGRP 2015 [150]	Liquids unloading	US	10% of well population in 2013 account for 65% of total unloading emissions.
Mitchell 2015 [89]	Gathering	US	30% of gathering sites accounted for 80% of fugitive methane emissions.
Mitchell 2015 [89]	Gathering	US	Fugitive emissions were over 5% of production for six out of 108 gathering sites, but less than 1% for 85 and less than 0.1% for 19.
NGML 2006 [92]	Extraction/ Gathering/ Processing	US	Top 10 leaks from each facility studied (12 well sites, seven gathering compressor stations, five processing facilities) contribute 58% of total leak emissions.
Clearstone 2002 [91]	Processing	US	The top 10 equipment leaks from each facility studied (four processing plants) contributed 54% of leak emissions.
Lechtenboehmer 2007 [99]	Transmission	Russia	0.5% of compressor and valve components account for 90% of leaks in the transmission network.
Harrison 2011 [159]	Compressor stations	US	One leak out of 2,800 sampled valves and flanges contributed 29% of the leaked emissions measured.
Subramanian 2015 [103]	Compressor stations	US	10% of compressor stations account for 50% of compressor venting emissions.
Venugopal 2013 [106]	Compressor stations	Canada	Compressor venting emissions were four times higher than those estimated in Lechtenbohmer et al. [99] due to the inclusion of older plant equipment.
Allen 2015 [155]	Pneumatics	US	20% of pneumatic devices account for 96% of pneumatic venting emissions.
Lamb et al. 2015 [104]	Distribution	US	Three individual pipeline leaks (of 230) account for 50% of total emissions.

The causes of such high emissions are likely to be due to the use of inefficient equipment that is either not the best available technique for the duty, is too

old, or has failed due to insufficient operation, maintenance and monitoring procedures [89, 161]. It is the authors' opinion that if appropriate operational control and maintenance procedures were carried out, these high emissions could be largely eliminated. One study [161] suggests that if a policy intervention successfully reduced emissions from these facilities to 'normal' levels, total supply chain emissions would be reduced by 65–87%. In reality this would be difficult to achieve as the super emitters within a group of facilities may change over time as the emitting equipment is identified/ fixed and others become larger emitters. However there is clearly great potential in targeting super emitters for cost-effective supply chain emissions reduction. It is worth noting that the elimination of high emissions would most likely economically benefit these facilities, as a high emission of gas equates to a large loss of product. Even so, super emitters still occur and it should be the responsibility of gas regulators to ensure that these emissions are eliminated.

4.3. The lack of data

Although a large quantity of data on GHG emissions has been collected since 2011, there remains a lack of representative, point source data. Most studies rely on data collected by the US Environmental Protection Agency (EPA) from 1996, which remains the most comprehensive dataset available for conventional well data. The EPA has adjusted their dataset in accordance with more recent data collection studies, as described further in Box 2.

Since 2011, a large amount of new data has been collected. New data has improved our understanding of the impacts of both conventional and unconventional gas, in particular with respect to:

- well completion emissions for unconventional gas [20, 77, 84, 105, 163];
- liquids unloading for all gas wells [25, 51]; and
- specific equipment emissions, such as compressors and pneumatically controlled devices [25, 77, 103, 155, 156, 158, 159].

Additionally, in 2011 the US EPA began publishing site and process-specific emissions data across various industries including the natural gas sector in the form of the GHG Reporting Program (GHGRP) [78]. This is further described in Box 3.

However, there are still significant gaps in data, in particular with regard to extraction from coal bed methane, liquids unloading, transmission, storage and distribution leaks. Perhaps the largest gap in available data is for offshore extraction emissions: only one study on offshore gas extraction emissions has been found [16]. Additionally, the transparency of LNG emissions estimates is limited, especially with respect to methane emissions.

In terms of regional distribution of available primary data, it is heavily skewed towards the US, particularly for upstream extraction emissions. In fact, all of the upstream data used in this analysis either used US emission estimates or conducted measurements within North America. More data is available from Russia for the transmission stage, but data from these sources [95, 97, 99], are

opaque and thus are limited in terms of reliability and applicability to other regions. Emissions across the natural gas supply chain are likely to be affected by regional regulation of industrial practices and environmental emission limits. Thus, the emissions data from the US may not be representative of other natural gas producing regions.

Box 2: EPA emissions data

The EPA data on GHG emissions in the natural gas supply chain represents the most comprehensive inventory in terms of breadth and representativeness. The main basis for this inventory is the 15-volume report on Methane Emissions from the USA natural gas system sponsored by the EPA and the Gas Research Institute [154]. The study measured emission rates from devices across six gas plants and 24 oil and gas production facilities. The data on methane and CO_2 emissions from various sources enabled the estimation of average emission factors for different equipment, processes and supply chain stages.

Each year, the EPA publishes an estimate of the annual GHG emissions associated with various industries, including natural gas production. This involves determining the national inventory of natural gas production sites and using the average emission factors to estimate annual US GHG emissions. Each year the emissions factors are assessed to determine whether they are still representative and whether they could be improved by more recent data.

Significant revisions have been made to the EPA emission factors in the past five years, particularly in response to increased unconventional drilling activity. For example, within the 2011 revision methane emissions from pre-production and extraction were increased from 0.2% to 1.6% of produced gas for conventional wells and to 3% for unconventional wells [53]. It is worth noting that in 1996, unconventional gas was not extracted in large quantities, so the emissions associated with unconventional gas was not included. This led the API/ ANGA [25] to carry out a study into unconventional drilling that suggested that emissions control technologies were being used more widely than previously assumed. Emissions from liquids unloading were also found to be shorter in duration than had been previously estimated. The EPA methane emission estimates were subsequently downgraded in 2013, particularly for well completions and liquids unloading [164].

The current set of EPA emission factors are an aggregation of multiple data sets. The representativeness of the data is unknown, but many studies have suggested that there are significant deficiencies and the uncertainty associated with the data may well be larger than stated within the EPA analysis [37]. The EPA/ GRI originally had an emissions estimation target accuracy of within 0.5% of total US gas production [154]. However, a demonstration of the uncertainty is the significant alterations to their emissions estimates between 2010 and 2011: methane releases from 0.16% of natural gas production in 2010 to 1.4% in 2011 [45]. Furthermore, the use of an average emission factor for all sites or processes does not represent the vast range of equipment in use.

Box 3: The GHG Reporting Program

The GHG reporting program (GHGRP) [78] is a database managed by the EPA which aggregates reported emissions from high emitting sectors in the US, including the natural gas industry. Data collection began in 2011, where all facilities that emit more than 25,000 t CO_2 eq. annually (using IPCC AR4 GWP factors) are required to report their emissions. Almost 2,000 oil and gas facilities were included within the GHGRP in 2013, including extraction, processing, transmission, storage, distribution, LNG imports and exports and LNG storage. This data does not represent the total annual US GHG emissions, but is used to inform improvements to the emission factors used within the US GHG inventory. The data collected represents approximately 85% of the US GHG inventory [113].

The program describes a number of methods by which each facility must estimate its associated emissions, depending on the existing environmental monitoring facilities already in place. The use of direct monitoring instruments is preferred but natural gas facilities without this equipment may use the default emission factors to estimate emissions. Thus, data collected from directly monitored sources provide a useful addition to the current compendium of data. However, the publication of some emission sources are not required, such as pneumatic devices, liquid storage tanks and acid gas removal scrubbers [165].

For the data that is reported, limitations exist in the form of transparency and validation: measurements are taken by each facility, often using unknown measuring devices which may vary in quality. Additionally, for event emissions such as liquids unloading, it is unknown how many events are actually measured: it may only be one measurement, which is assumed to be the same across wells within the same category. Whilst this is a potentially useful data source, the representativeness of the sample is insufficient due to a lack of transparency, excluded emissions sources and the boundary on the size of the facility capacity.

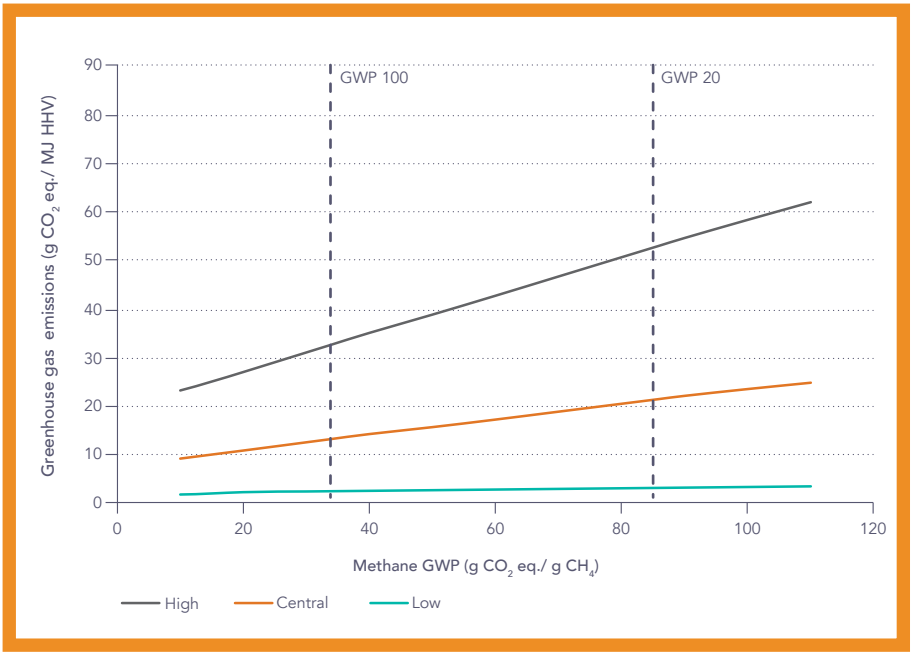
4.4. Methods of measurement and estimation

Although this report has demonstrated that there is significant variation in the emissions associated with the gas supply chain, there remains much uncertainty that stems from emissions measurement and estimation methods. As discussed below, there are significant differences in estimates between top-down and bottom-up methane measurements. There are also a number of issues associated with assumptions made in life cycle assessment studies, such as allocation of emissions to co-products, the assumed Estimated Ultimate Recovery (EUR) of the gas well, the assumed natural gas composition and the assumed global warming potential (GWP) of methane. These issues are described and their impacts on emission estimates are discussed.

4.4.1. Global warming potential of methane

As described in Section 2.5 Box 1, the GWP of methane varies over time. Typically, a GWP of 34 g CO_2 eq./ g CH_4 is used and this value has been used throughout the paper to describe the combined GHG emissions of methane and CO_2. However, other studies have used GWP values between 21 and 86 g CO_2 eq./ g CH_4. There is no single correct figure to use in an analysis of this type and so in order to capture this variation, a sensitivity analysis of the impact of methane GWP on the total GHG emissions of the supply chain was conducted. Total supply chain GHG emissions for the central revised estimate (as shown in Figure 15) was estimated for different values of GWP of methane and shown in Figure 20. The effect of GWP on GHG emissions is linear and large in magnitude. The central estimate GHG emissions using a GWP100 value of 34 is 13.6 g CO_2 eq./ MJ HHV, whereas a GWP20 of 86 increases this estimate to 23 g CO_2 eq./ MJ HHV. This increased value increases the contribution of supply chain emissions to 40% of those that would be emitted from a natural gas power plant (approximately 56 g CO_2 eq./ MJ HHV).

FIGURE 20
The impact of GWP of methane on total supply chain GHG emissions
Total supply chain GHG estimates using GWP methane values for the low, central and high revised estimates as per Figure 15.



4.4.2. Top-down versus bottom-up emission estimates

A large number of studies have estimated methane emissions from top-down measurements in recent years, all of which have been based in North America. Most of the studies compare their emission results to the EPA bottom-up estimates. Approximately half of the studies estimate emissions to be 1.5–2.5 times higher than the EPA estimates [44, 45, 166–171], whilst the other half estimate emissions to be comparable [40, 46, 172–174]. One study by Petron et al. [43] cites an emission estimate two orders of magnitude higher, but this appears to be due to methodological uncertainties [175–177]. A subsequent estimate by the same authors using a different estimation methodology suggested emissions were still higher but only by a factor of 2 [168].

However, large uncertainties associated with both estimation methods render a comparison between top-down and bottom-up estimates inconclusive [173, 174]. Generally, bottom-up estimates tend to underestimate emissions. In order to generate an accurate emission factor for bottom-up estimates, sampling measurements must be representative of the population [37]. Inaccuracies may occur via either unaccounted emission sources, or the presence of super emitters within the population that are not represented within the emission factors [25, 37, 105, 154]. Using emission factors on a facility or single process scale are likely to cause inaccuracies because facility emissions are highly variable, as demonstrated throughout this report. Alternatively, using average emission factors on a larger multi-facility region may underestimate emissions where there are super emitters within the region (see section 4.2.5) [178].

Conversely, top-down estimates may overestimate emissions, due to the difficulty in allocating the atmospheric methane concentrations to specific sources [37, 71, 171]. There is a tendency to allocate measured emissions entirely to the natural gas industry as opposed to the oil industry or even livestock emissions, landfill sites or geological seepage, which could be present in the area [178, 179].

Whilst this paper excludes the emissions from associated oil wells, it should be noted that this may be a significant additional source of methane emissions. Many associated oil wells contain stranded gas, where it is deemed uneconomic to capture and process the natural gas [180]. Instead, oil well operators may vent or flare the extracted gas [181], representing an additional source of emissions not accounted for within bottom-up estimates and may account for some of the differences documented between bottom-up and top-down estimates.

Top-down approaches often highlight emissions that may be from the gas sector and are not accounted for in bottom-up approaches [37, 105, 182], but they are not able to determine the cause of these [e.g. 183]. The cause of big emitters must be detected by point source emission measurements. Allen [37] proposes combining top-down and bottom-up approaches to improve understanding of methane emissions and their sources. Results could then be compared to regional emissions inventories, highlighting the important sources of emissions that are often unaccounted for [105]. A better understanding of the very high emitters that might skew the distribution of emission sources could improve the targeting of policies to reduce methane emissions.

4.4.3. Cross-sectional estimates

Emissions analyses can normally be categorised as either cross-sectional or longitudinal. Cross-sectional estimates are quantified over a variety of processes or a region for a fixed time period, whereas longitudinal estimates follow a single process or route over the whole life cycle. Top-down measurements generate data for a cross-sectional analysis, where the emissions are expressed as a mass emitted for a region over a specific time frame. The EPA annual GHG inventory is also a cross-sectional analysis of a variety of sectors for each year across the US. Thus these cross-sectional results are constrained to the point in time of analysis.

For these regional estimates, during the time frame considered, different wells will be at various stages of their lifespan. If, for example, during that time many early-stage well completions occurred, there would be more emissions associated with upstream gas production [71]. The aggregation of emissions from different wells and processes at different life cycle stages means that it is very difficult to transform these estimates into an estimate for the life cycle of a single well or supply route, without detailed analysis and activity data.

Cross-sectional estimations are useful in determining the magnitude or changes in emissions for a region, but less useful from a technological perspective. The cross-sectional estimates also give little indication of the environmental performance of the natural gas supply chain from a life cycle perspective. This can only be achieved with a longitudinal life cycle assessment of the natural gas supply chain. Longitudinal life cycle assessments of the supply chain instead determine all the emissions associated with a well or play or unit of production across the total life span of the supply chain. From this, the total impacts associated with developing the natural gas sector can be determined.

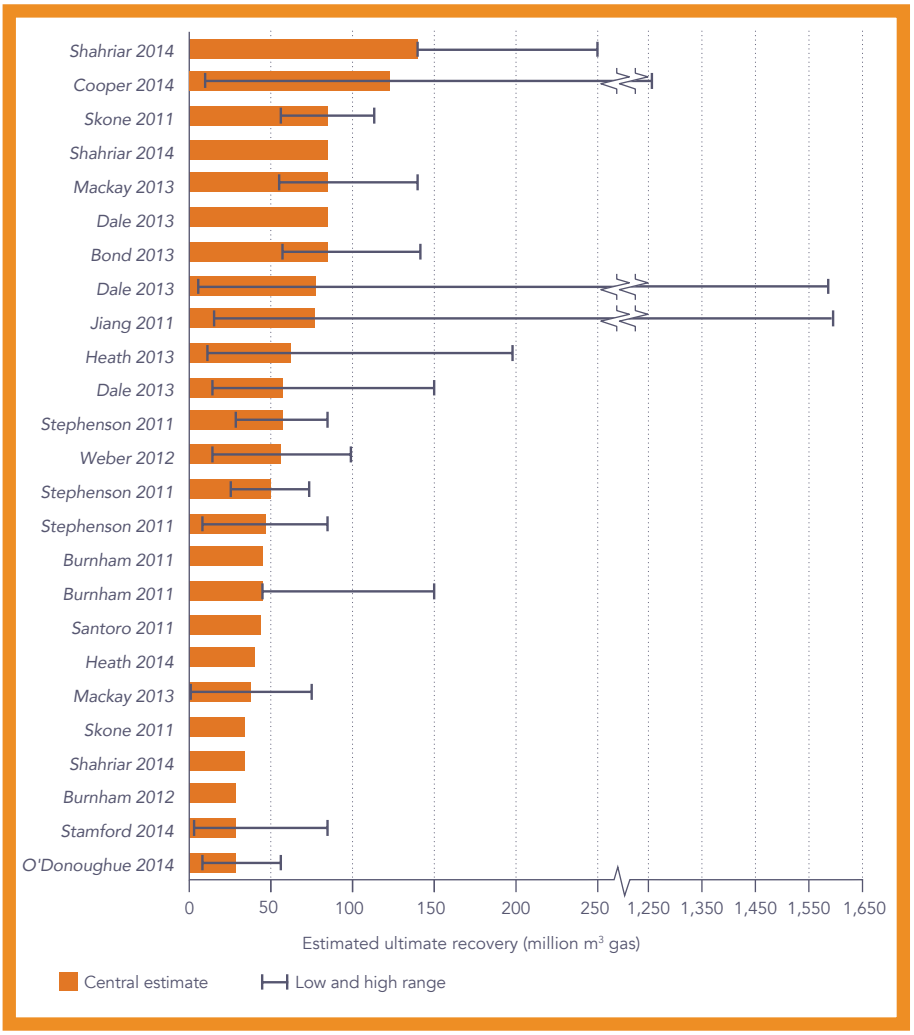
> The cross-sectional estimates give little indication of the environmental performance of the natural gas supply chain from a life cycle perspective. This can only be achieved with a longitudinal assessment.

4.4.4. Estimated ultimate recovery of wells

One of the biggest causes of the large variation in supply chain emissions estimates may be due to the assumed estimated ultimate recovery (EUR) of gas wells being studied [22, 66, 67, 71, 184]. The EUR is the measure of economically feasible gas extraction and is dependent on the size of the well, the ease of extraction (i.e. well pressure and permeability of the formation) and the energy market, which governs the economic feasibility of production [71]. The EUR determines the total volume of gas produced and thus the total quantity of fuel for heat or electricity generation.

Different estimates of gas well EUR range three orders of magnitude, from 2 million m^3 to 2,500 million m^3 [22, 30–32, 54, 66, 67, 70, 73, 185] as shown in Figure 21. Most studies reflect the large natural variation in EUR across different wells by using a range, normally between 10 million and 100 million m^3. Burnham and Clark [54] suggest that conventional wells have historically had a lower EUR (28 million m^3) than shale wells (45–150 million m^3) and that newer shale wells are even greater.

FIGURE 21
Estimates of EUR across the literature, by reference
Error bars indicate high and low values where a range of EUR has been considered.

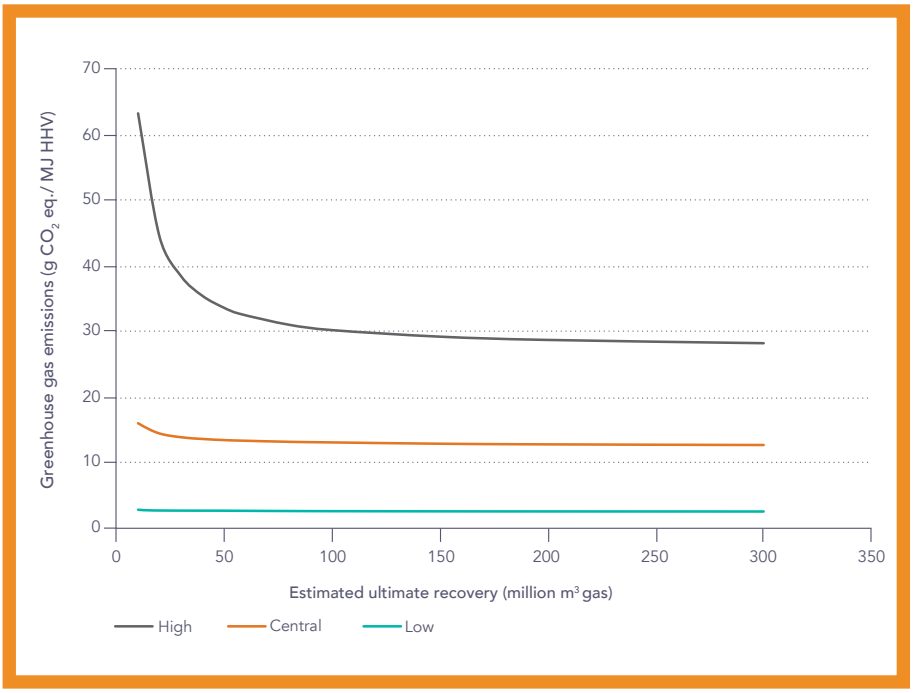


Within this paper, GHG estimates have assumed an EUR of 57 million m^3 (the median estimate from literature studied). However, the effect of the assumed EUR is significant, as can be seen in Figure 22. In order to determine the impact of EUR on GHG estimates within this paper, the expected supply chain GHG emissions were estimated under different EUR scenarios, as shown in Figure 22. A range of 10–300 million m^3 was used, as this represents the majority of the estimates found in the literature and above which GHG emissions change very little.

As shown in Figure 22, whilst the central and low GHG estimates are not significantly affected by the change in EUR, the high GHG estimate varies by a factor of two. Other studies have also suggested that levelised emissions may vary by a factor of two [e.g. 22, 67, 69]. The reason that this paper's high estimate varies significantly more than the central or low is due to the larger contribution from 'intermittent' emissions. The volume of intermittent emissions is not significantly affected by the EUR of a well. Therefore, because we divide our emissions by the EUR to produce levelised emissions (in case per MJ of energy content delivered), these levelised intermittent emissions are inversely proportional to the assumed EUR. Other more 'continuous' emissions, such as leaks and vents, are proportional to the EUR and so levelised emissions are not affected by the assumed EUR [17]. The high supply chain

GHG estimates have proportionally more contribution from well completions and liquids unloading, therefore they are more influenced by the assumed EUR value.

FIGURE 22
The impact of assumed EUR on the total supply chain GHG emissions
Revised estimates of low, central and high emissions are used to demonstrate the range of expected emissions.



4.4.5. Co-product allocation

Another factor that affects the magnitude of emissions associated with the gas supply chain is whether the study accounts for co-products such as natural gas liquids (NGLs) and how emissions are allocated to the different co-products. There may be a number of co-products from the natural gas supply chain, the most common being natural gas liquids, which are the heavy hydrocarbons that are separated at the processing stage. In a multiple product system, it is unfair to allocate all emissions to just one product, natural gas.

In theory, the total emissions should be allocated somehow to each product. However, allocation of emissions to different co-products creates an additional layer of uncertainty and methodological difference between studies. Life cycle assessment studies are normally methodologically guided by the ISO 14040/14044 guidance [186, 187], which sets out different methods of accounting for co-products. The preference is to avoid allocation by expanding the system boundary being considered, or by 'displacement' of co-products.[8] If this cannot be feasibly achieved, the emissions should be divided between the co-products by economic value, mass or energy content.

8. Displacement of co-products is used when there is another 'typical' method of generating the co-product as a primary product (e.g. heavy hydrocarbons from an oil well). The method of displacement involves subtracting the avoided burden, the emissions associated with this typical process that would otherwise have been used to create the product. This is essentially crediting the natural gas life cycle chain with avoided emissions.

The different allocation methods, or the assumed quantity of co-product generated, will create very different results. Zavala-Araiza et al. [39] provide a good example of this: if a gas well produced 170 m^3 of gas for every barrel of oil, the allocation according to energy content would be a 50:50 split (therefore one would divide the total emissions for gas by half). If the allocation was based on mass the split would be 60:40 (gas: liquid), whereas on an economic basis the split would be 19:81.

Most studies investigated in this report have allocated emissions based on energy content of co-products [e.g. 16, 39, 66, 70, 71], or by mass [83]. Skone [16] and Stephenson et al. [70] allocate 88% of the extraction emissions to the natural gas product with the remainder allocated to the heavier hydrocarbon liquids. However, the quantity of NGLs varies significantly for different wells [as seen in 51]. Furthermore, many studies do not account for co-products at all [e.g. 188]. Therefore this is a significant source of uncertainty in all estimates of gas emissions.

4.4.6. Natural gas composition

The composition of extracted gas may have a large impact on the supply chain emissions. This is a multifaceted issue, but impacts upon the following emissions:

- **Fugitive methane.** A lower concentration of methane in extracted gas will reduce the quantity of fugitive methane emissions from the extraction stage.
- **Processing energy requirements.** A higher concentration of impurities increases the energy requirements of the processing stage, thereby increasing associated emissions.
- **Processing non-combusted CO_2 emissions.** A higher concentration of CO_2 in extracted gas causes an increase in CO_2 vented emissions during the processing stage where it is separated.

Therefore, a low methane concentration in the extracted gas will cause lower fugitive methane emissions, but higher processing energy requirements and more CO_2 venting emissions (with a higher CO_2 content). Additionally, a low methane concentration reduces the total quantity of produced gas, which would increase levelised emissions, as described in section 4.4.4. Only one study was found that compared total supply chain emissions for varying natural gas compositions [71], suggesting a potentially significant effect but giving little granular detail. A more comprehensive study would provide clarity on this compounded issue. As methane has such a high GWP characterisation factor (34 for a 100 year time horizon), small changes in composition may have a large effect on GHG emissions if fugitive emissions are high. It is worth noting that this is only significant prior to the processing stage. It is assumed that the methane concentration of gas post-processing will remain reasonably constant.

5. Conclusions and recommendations

This White Paper has documented a thorough and systematic review of estimates of methane and CO_2 emissions from the natural gas supply chain and examined the main factors affecting such estimates, assessing over 400 papers. The literature was analysed with regard to the range of emissions, data availability and the different estimation methods used. Here, key conclusions are outlined, alongside a summary of the research needs, in order to help improve our understanding of greenhouse gas (GHG) intensity in the natural gas supply chain and identify pathways to further reduce natural gas supply chain GHG emissions.

5.1. Overall emissions

The range of estimates of methane emissions across the supply chain is from 0.2% to 10% of produced gas, which is equivalent to between 1 and 58 g CO_2 eq./ MJ HHV (higher heating value) assuming a global warming potential of 34. This extremely large range is in part due to different natural gas extraction, processing and transport routes which use different processes across different regions with varying levels of regulation. The majority of estimates are between 0.5% and 3% of produced gas, which is equivalent to 2.9–17 g CO_2 eq./ MJ HHV.

Accounting for both methane and CO_2 supply chain emissions, estimates of GHG emissions range from 2 to 42 g CO_2 eq./ MJ HHV. Putting these values into context, the GHG emissions associated with natural gas power plant electricity generation are estimated to be approximately 56 g CO_2 eq./ MJ HHV (400 g CO_2 eq./ kWh).

By removing outlying estimates, excluding data that does not represent the use of emissions-minimising techniques (such as reduced emissions completions and plunger lifts for liquids unloading) and excluding over-conservative fugitive emission assumptions, this report estimates a revised range of 2.7–32.8 g CO_2 eq./ MJ HHV, with a central estimate of 13.4 g CO_2 eq./ MJ HHV. In the context of electricity generation, total GHG emissions are 419–636 g CO_2 eq./ kWh electricity generated, with a central estimate of 496 g CO_2 eq./ kWh: this is well below typical coal GHG estimates of around 1,000 g CO_2 eq./ kWh. However, these supply chain emissions still represent a significant contribution to life cycle emissions: e.g. for electricity generation from natural gas, supply chain emissions would contribute 4–34% (with the remainder from power plant emissions and electricity transmission). Furthermore, in a future scenario where CCS is employed, the relative contribution from supply chain emissions would increase proportionally.

Additionally, although this report has attempted to estimate emissions for an efficient natural gas supply chain, much of this was based on the authors' judgement and should be interpreted as broad guidance only. With appropriate legislation and the use of best available techniques, as well as effective operational control and maintenance procedures, emissions across the supply chain could be significantly lower still. Further work is required to determine what level of emissions reduction could feasibly be achieved using best-available techniques and effective operation and maintenance procedures. Determining the emissions associated with effective use of natural gas is the key to understanding the potential role of natural gas in meeting global decarbonisation targets.

5.2. Key emission sources

The key emission sources identified within the literature are from well completions, liquids unloading, pneumatic devices and compressors. The largest emission estimates from the literature are those with high well completion estimates for unconventional gas wells. During this process, the hydraulic fracturing fluid returns to the surface whilst the gas flow increased to the high initial production rate. However, primary data collected in recent years has shown that the use of Reduced Emission Completions (RECs) equipment can minimise these emissions to a negligible amount.

> Estimates of liquids unloading emissions are also highly variable, in particular from recent primary measurements.

Estimates of liquids unloading emissions are also highly variable, in particular from recent primary measurements. Whilst this may represent the greatest emission source for some wells, most wells do not vent at all during unloading. However, the distribution of emissions across the well population is not fully understood. Further research is required to determine the factors affecting unloading emissions such as well age, reservoir properties, equipment used and operational strategies.

There are opportunities for further reduction in supply chain emissions in particular for fugitive emissions during extraction, transmission and distribution stages. Transmission stage methane emissions have a potentially large contribution but are highly variable across supply chains with different transmission distances. With reduced emissions during well completions, liquids unloading and workovers, the majority of emissions originate from methane leaks and vents. As a subject of further research, determining feasible limits for methane emissions across the supply chain would contribute to understanding the emissions potential for natural gas.

5.3. Super emitters

There is a large body of evidence suggesting that a small number of gas extraction, processing and transmission facilities are 'super emitters'. These have been found at various facilities across the whole supply chain, including for well completions, liquids unloading, leaking pipework, pneumatic devices and compressors. These are likely to occur via the use of ineffective process equipment and poor operational and maintenance strategies. Again, it should be considered that when best available techniques are applied, as well as appropriate maintenance and operation procedures, these high emissions would be largely eliminated.

5.4. Methodological differences in estimates

Supply chain emission estimates differ greatly in terms of methodological variations, as well as differences in assumptions made. Firstly, many top-down methane emission measurements have been carried out in North America. These estimates are useful in validating point source emission estimates and identifying whether bottom-up estimates may be underestimating emissions. However, they provide little detail in terms of detecting where such underestimates may occur. Bottom-up point source measurement in combination with local leak detection operations could help to prevent missing unknown emission sources.

Methodological assumptions within life cycle assessment studies of the natural gas supply chain also vary significantly across the literature and can have a major effect on the estimated emissions. Important assumptions include:

- The selection of global warming potential (GWP) of methane has a significant impact on supply chain emissions. Increasing the GWP from 34 (100 year time horizon) to 86 (20 year) increased the revised supply chain emissions estimates by 20–84%.
- The assumed estimated ultimate recovery (EUR) of the gas well. The range of EUR estimates spans two orders of magnitude and studies investigating the impact of such a range find that levelised GHG emissions vary by a factor of two.
- The allocation of emissions to co-products, in particular heavier hydrocarbon liquids. Many studies do not allocate any emissions to co-products of the natural gas supply chain, resulting in an overestimate of natural gas emissions.
- Limitations of the supply chain boundaries of life cycle assessment studies cause differences in GHG estimates, in particular accounting for liquids unloading. A number of older studies did not account for liquids unloading, due to a misinterpretation with regard to whether unconventional wells require this process. Other boundary limitations include not accounting for emissions such as the embodied impacts of purchased fuel [71].
- The composition of extracted natural gas varies significantly across the global well population and has a significant impact on the expected GHG emissions. The impacts of composition on GHG emissions are

multifaceted and more research is required to determine the scale of the impact across known gas compositions.

5.5. Lack of data

Whilst there has been a significant drive to collect new data, there is still an unrepresentative data set for a number of key emission points over the natural gas supply chain. Specifically, more data is required for offshore extraction, coal bed methane extraction, liquids unloading, well completions with RECs and transmission and distribution pipelines. Additionally, more data and transparency with respect to LNG stage methane emissions is required. In terms of regional distribution, the available data is almost exclusively from the US. Whilst this may be applicable to other regions, both geological formations and regional regulation play a large part in the supply chain emissions and so data from other regions would help to validate the existing data.

5.6. Research needs

It is clear that whilst potential supply chain GHG emissions could be reduced significantly from current estimates, more research is required to define both by how much GHG emissions could be reduced to, and by which technological or political mechanisms these reductions could be achieved. Specifically, further research is required in the following areas.

- In order to gain a representative estimate of supply chain emissions across the global natural gas industry, more publically available and transparent emissions data are required for regions beyond North America. Both reservoir properties and regulatory practices bear a significant impact on emissions, which are likely to differ greatly across different regions.
- A greater causal analysis of the factors affecting different supply chain emissions is required in order to understand the mitigation potential at each stage. Such factors include the selection of equipment, operational practices, the regulatory environment, reservoir properties and gas composition. This is particularly salient to the liquids unloading process and would require analysis from engineering, economic and political perspectives.
- In order to help determine the potential of natural gas to contribute to low carbon energy systems, a quantification of how much supply chain emissions can be minimised is required. The use of emissions-minimising technology of operations may be limited by economic feasibility and this multifaceted trade-off must be analysed in the context of future energy market scenarios.
- Analysis on the impact of regional regulation on the emissions associated with supply chain is required, in particular with respect to 'super-emitting' facilities. Targeting such facilities would yield the greatest environmental improvements and improve the contribution of natural gas towards a low carbon energy system.

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Appendix

A. Estimation of levelised GHG emissions

The following description shows an example of the method used by the authors to convert the different estimations from the literature into common units. As an example two conversions are shown: from the volume of gas leaked as a proportion of the total produced gas into equivalent CO_2 emissions per unit of energy content (HHV); and the volume of gas emission from a single event to equivalent CO_2 emissions per unit of energy content (HHV).

Emissions expressed as a proportion of total gas produced:

$$GHG\ emission\left(\frac{g\ CO_2\ eq.}{MJ\ HHV}\right) = \frac{\boldsymbol{x}\ (vol\%).\ MF(vol\%).\rho_{CH4}\left(\frac{kg}{m^3}\right).1000\left(\frac{g}{kg}\right).\ GWP100\ \left(\frac{gCO_2}{gCH_4}\right)}{(1 - L(\%vol)).\ HHV\left(\frac{MJ}{kg}\right)}$$

where $\boldsymbol{x}$ is the proportion of gas emitted per volume of produced gas, *MF* is the average fraction of methane within the gas that is emitted, P_{CH4} is the density of methane, *GWP100* is the global warming potential characterisation factor of methane for a 100 year period, *L* is the volume of gas that is lost across the whole supply chain as a proportion of the EUR and *HHV* is the higher heating value of natural gas. Parameter values utilised within this study are:

MF = 80% (vol/vol)

GWP100 = 34 g CO_2/ g CH_4

L = 12% of produced gas

HHV = 38.1 MJ/m^3 of produced gas

The proportion of gas loss, *L*, is a critical factor which allows the determination of the total energy content of delivered gas. This loss consists of the summation of fugitive, vented and flared emissions as well as gas used as fuel: the difference between the quantity extracted and the quantity delivered. The value of 12% was estimated as the summation of the median gas loss estimates across the whole supply chain. Gas loss assumed across each stage is as follows: completion = 0.014%; extraction = 0.5% (vents and flares); liquids unloading = 0.05%; workovers = 0.004%; processing = 0.3% (fugitive) + 4% (fuel) + 2% (CO_2 vent) + 0.6% (flare); transmission = 0.5% (fugitive) + 2% (fuel); storage = 0.1% (fugitive); distribution = 1.5% (fugitive).

When single emission sources such as well completions are expressed as a volume of gas emitted, the same calculation is carried out but with the addition of dividing through by the EUR, the total volume of gas produced by the well (m^3). The EUR was assumed to be 57 million m^3 as the median estimate across the literature.

B. Summary of literature and revised estimates

The following tables summarise the literature and revised estimates of GHG emissions for each stage of the supply chain. The central revised estimate is also expressed in different functional units: per cubic metre of extracted gas (at 15.6°C and 1 atm); and per kWh of electricity generated by a gas power plant.

The conversion from a MJ of energy content to extracted volume is the following:

$$1\ MJ\ delivered\ gas = \frac{1}{HHV}\ m^3\ delivered\ gas = \frac{1}{HHV} \cdot \frac{1}{(1-L)}\ m^3\ extracted\ gas$$

Where *HHV* is the higher heating value of gas product per volume of gas (38.1 MJ/ m^3) and *L* is the proportion of extracted gas that does not reach the point of delivery (12% as per Appendix A), for example through venting or use as a fuel along the supply chain. Thus, the conversion factor from MJ of delivered gas to m^3 of extracted gas is 0.030.

The conversion from MJ of energy content within natural gas to kWh of electricity generated is the following:

$$1\ MJ\ delivered\ gas = \varepsilon \cdot \frac{1}{3.6}\ kWh\ electricity\ generated$$

Where ε is the thermal efficiency of the power plant, assumed here to be 50%. Thus, the conversion factor from MJ of delivered gas to kWh of electricity generated is 0.139.

Table 6 also gives a summary including the LNG emissions. Note that for the revised estimates using a functional unit of MJ energy content delivered, it was necessary to transform the upstream emissions estimates to reflect the fact that less gas is delivered per unit of extracted gas for LNG than for the non-LNG supply chain. Total gas lost *(L)* over the LNG stages was estimated to be an additional 11.5%: Fuel for liquefaction and regasification 9.5%, venting, flaring and fugitive 2% (including boil-off gas).

Supply chain stage		Literature (g CO_2 eq./ MJ HHV)				Revised (g CO_2 eq./ MJ HHV)							Central revised estimate in other functional units:	
Minimum		Minimum	Mean	Median	Maximum	Low	High	Central estimate					g CO_2 eq./ kWh electricity generated	g CO_2 eq./ m^3 produced gas
								Total	Methane	Carbon dioxide	% CH_4	% CO_2		
Exploration		0	0	0	0	0	0	0	0	0	0%	0%	0	0
Pre-production	Site preparation	0.0078	0.17	0.15	0.59	0.0078	0.59	0.15	0	0.15	0%	100%	1.1	5.1
	Drilling	0.0078	0.21	0.19	0.57	0.0078	0.57	0.19	0	0.19	0%	100%	1.4	6.4
	Hydraulic fracturing	0.12	0.26	0.19	0.52	0.12	0.52	0.19	0	0.19	0%	100%	1.4	6.4
	Well completion	0	1.8	0.081	86.6	0	0.32	0.038	0.025	0.013	65%	35%	0.27	1.3
Extraction	Normal operation	1.1	4.6	3.8	11.5	1.1	4.7	2.9	2.5	0.33	89%	11%	20.7	97.0
	Liquids unloading	0	2.1	0.27	105.5	0	3.3	0.27	0.24	0.027	90%	10%	1.9	9.0
	Workovers	0	3.3	0.085	86.6	0	1.6	0.038	0.025	0.013	65%	35%	0.27	1.3
Processing		0.86	5.2	4.6	13.6	0.86	9.1	4.6	1.3	3.3	29%	71%	33.4	156.3
T, S & D		0.60	8.9	6.3	29.2	0.60	12.0	5.0	3.9	1.1	78%	22%	36.0	168.7
Estimated total (without LNG)		**0**	**13.2**	**13.0**	**42.0**	**2.7**	**32.8**	**13.4**	**8.1**	**5.3**	**60%**	**40%**	**96.4**	**451.3**

TABLE 5
Summary of literature emissions estimates and revised estimates as per the description in Section 4.1 for each supply chain stage
For the revised central estimate, the proportional contribution of methane and carbon dioxide are also given (both in units of g CO_2 eq./ MJ HHV). The central revised estimate is also given in two other functional units: per kWh of electricity generated and per m^3 of gas produced (at 15.6°C and 1 atm).

Supply chain stage		Literature (g CO_2 eq./ MJ HHV)				Revised with LNG (g CO_2 eq./ MJ HHV)							Central revised estimate in other functional units:	
Minimum		Minimum	Mean	Median	Maximum	Low	High	Central	Methane	Carbon dioxide	% CH_4	% CO_2	g CO_2 eq./ kWh electricity generated	g CO_2 eq./ m^3 produced gas
Exploration		0	0	0	0	0	0	0	0	0	0%	0%	0	0
Pre-production	Site preparation	0.0078	0.17	0.15	0.59	0.0090	0.67	0.2	0	0.17	0%	100%	5.1	5.8
	Drilling	0.0078	0.21	0.19	0.57	0.0090	0.66	0.2	0	0.22	0%	100%	6.4	7.3
	Hydraulic fracturing	0.12	0.26	0.19	0.52	0.14	0.60	0.2	0	0.22	0%	100%	6.4	7.3
	Well completion	0	1.8	0.081	86.6	0	0.36	0.0	0.028	0.015	65%	35%	1.3	1.5
Extraction	Normal operation	1.1	4.6	3.8	11.5	1.2	5.4	3.3	2.9	0.38	89%	11%	97.0	111.5
	Liquids unloading	0	2.1	0.27	105.5	0	3.8	0.3	0.28	0.031	90%	10%	9.0	10.4
	Workovers	0	3.3	0.085	86.6	0	1.8	0.0	0.028	0.015	65%	35%	1.3	1.5
Processing		0.86	5.2	4.6	13.6	0.99	10.4	5.3	1.5	3.8	29%	71%	38.4	156.3
T, S & D		0.60	8.9	6.3	29.2	0.69	13.9	5.8	4.5	1.3	78%	22%	41.4	168.7
Estimated total (without LNG)		**0**	**13.2**	**13.0**	**42.0**	**3.1**	**37.7**	**15.4**	**9.3**	**6.1**	**60%**	**40%**	**110.8**	**451.3**
LNG	Liquefaction	2.8	6.3	6.4	10.5	2.8	10.5	6.4	0.99	5.4	15%	85%	188.0	216.1
	Transport	0.9	2.4	2.0	7.3	0.9	7.3	2.0	0.22	1.8	11%	89%	58.2	66.9
	Regasification	0.3	0.9	0.5	2.5	0.3	2.5	0.5	0.10	0.4	18%	82%	15.8	18.1
	LNG Total	3.9	9.6	8.9	20.3	3.9	20.3	8.9	1.3	7.6	15%	85%	262.0	301.1
Estimated total (with LNG)		**11.2**	**20.1**	**18.3**	**31.1**	**7.0**	**58.0**	**24.3**	**10.6**	**13.7**	**44%**	**56%**	**175.1**	**713.3**

TABLE 6
Summary of literature emissions estimates and revised estimates as per the description in Section 4.1 for each supply chain stage, including LNG processes

For the revised central estimate, the proportional contribution of methane and carbon dioxide are also given (both in units of g CO_2 eq./ MJ HHV). The central revised estimate is also given in two other functional units: per kWh of electricity generated and per m^3 of gas produced from a well (at 15.6°C and 1 atm).

Glossary

Acid gas	Natural gas containing carbon dioxide and hydrogen sulphide.
Activity factor	A number that quantifies the number of devices or pieces of equipment that exist. Multiplied by an emission factor to calculate the total quantity of gas leaked.
Associated gas	Gas contained within the same formation as oil.
Basin	A low lying area that typically collects sediment.
Bleed	The release of a gas or liquid from a closed system.
Blowdown	The intentional release of pressurised gas.
Boil-off	Liquefied gas that is unintentionally heated to above its boiling point.
Boosting station	A compressor station that increases pressure in a transmission pipeline.
Bottom-up	Emission estimates based upon source-specific measurements.
CCS	Carbon capture and storage: a process involving the capture and long term storage of carbon dioxide.
Climate forcing	The difference in energy absorbed by the Earth and that radiated into space.
Coal bed methane	Methane that is extracted from coal beds.
Combustion	The process of reacting a substance with oxygen to release heat and light.
Compressor	A mechanical device that increases the pressure of a compressible fluid.
Condensate	A hydrocarbon fraction that condenses out of natural gas as it is cooled.
Conventional gas	Commonly defined as gas found within high permeability sandstone or carbonate formations.

Dehydrator	Process equipment that separates water from gas.
Dig-in	The accidental destruction of a pipeline usually by activities relating to construction.
Distribution	A network of typically low pressure pipelines that connect the transmission network to commercial consumers.
Dry gas	Natural gas with minimal heavy hydrocarbon and impurity content, mostly methane.
Emission factor	A number that quantifies the average amount of gas that typically leaks from a device or piece of equipment over a defined period of time. Multiplied by an activity factor to calculate the total quantity of gas leaked.
EUR	Estimated ultimate recovery: an estimate of the total gas resource that a well is likely to produce throughout its lifetime.
Exploration	The process of identifying petroleum reservoirs.
Flared gas	Natural gas that has been purposefully combusted.
Flashing	The evaporation of liquid into a vapour, usually by a rapid reduction in pressure.
Flowback	The water based solution that flows back to the surface during and after the process of hydraulic fracturing.
Fracking fluid	Liquid used during the hydraulic fracturing process.
Fugitive emissions	Gas that has been released unintentionally to the atmosphere.
Gas processing	A variety of processes that separate impurities from natural gas.
Gas well	A well-bore drilled into a rock formation containing gas.
GWP	Global warming potential: the time integrated radiative forcing of a gas relative to that of carbon dioxide.

Higher heating value	Energy released from a substance that has been combusted and allowed to cool back to pre-combustion temperature (usually a 'standard' temperature of 15°C).
Horizontal drilling	A drilling technique that involves drilling at angles that are parallel to the surface.
Hydraulic fracturing	A well stimulation technique that involves the use of high pressure to fracture rock formations.
kWh	One kilowatt of power expended for one hour.
Liquefaction	The process of cooling a gas to below its boiling point.
Liquids unloading	The process of removing fluids which have accumulated in a well.
LNG	Liquefied natural gas: natural gas that has been cooled below its boiling point.
LNG tanker	A ship that is specifically designed to store and transport liquefied natural gas.
Lower heating value	Energy released from a substance upon combustion, minus the heat of vapourisation of water.
Mains pipeline	A distribution line that serves as a common source of supply for more than one service line.
Open-ended line	A section of pipe that is open to the atmosphere.
Permeability	A unit of measurement that describes the ability of a material to transmit fluids.
Plunger lift	A device that removes liquids (or materials) that have accumulated within a well.
Pneumatic value	A value that operates using pressurised gas.
Porosity	The percentage of a rock that is taken up by pore space.
Power plant	An industrial facility that produces electrical power.
Produced gas or methane	The total quantity of gas or methane that is extracted from a well.

Recompletions	A variety of processes that improves the flow characteristics of a production well that has declined in production rate.
Regasification	The process of warming a liquefied gas back to atmospheric temperature.
Rod-packing	The seal around a reciprocating compressor piston.
Seal oil	Oil that flows through a compressor as part of the pressure sealing mechanism.
Seismic surveying	A geophysical survey to gather information about rock formations, usually for the purposes of petroleum exploration.
Service pipeline	A distribution line that transports gas from a common source of supply to a customer meter.
Shale gas	Gas extracted from shale formations.
Sour gas	Natural gas with hydrogen sulphide and/ or carbon dioxide that requires removal.
Storage	High pressure reservoirs that are able to store gas for periods of high demand or interrupted supply.
Super emitter	An emission source that leaks far in excess of the average.
Sweet gas	Natural gas with very little hydrogen sulphide or carbon dioxide.
Tight sands	Gas extracted from sandstone formations with a permeability of less than 0.1 millidarcy.
Top-down	Emission estimates based upon atmospheric measurements.
Transmission	A network of typically high pressure pipelines that transport gas from the site of production to commercial markets.
Unconventional gas	Commonly defined as gas found within low permeability rock formations that typically require well stimulation techniques to increase commercial viability.
Venting	The intentional release of a gas to the atmosphere.

VOCs	Volatile organic compounds: a general term describing a broad variety of organic compounds that have a strong tendency to evaporate into the atmosphere.
Well completions	The process of preparing a well for production or injection.
Well pad	A surface installation containing well support infrastructure.
Wet gas	Natural gas with heavier hydrocarbons such as ethane and butane.
Workovers	An alternative term for recompletions.

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