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Reducing Emissions from Natural Gas Supply Chains

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REDUCING EMISSIONS FROM NATURAL GAS SUPPLY CHAINS

Executive Summary

This technical review has been undertaken with the aim of providing a summary of the current status of research into greenhouse gas emissions in the natural gas supply chain. Although 90% or more of the CO_2 produced at gas fired power plants can be captured, emissions from the supply chain may reduce the near-zero-emission image of gas as an energy source. Emissions are predominantly from two sources:

1. Methane emissions during production and also fugitive emissions during transport.
2. CO_2 emissions from gas production installations, gas purification plants, pipeline compressors, LNG liquefaction plants, ships and receiving terminals.

This is a literature review focusing on research that has been conducted on emissions in the natural gas supply chain. The review aims to look at how the quantities emitted are calculated and how assessments are conducted at each part of the supply chain. Assessments are also made in the literature as to how these might change, e.g. due to the greater production of shale gas, the use of long-distance pipelines and the use of LNG/gas with high CO_2 concentrations and the impact this may have on emissions. A variety of techniques are available to reduce methane and CO_2 emissions substantially from the supply chain which have been looked at in numerous studies.

An evidence assessment was carried out by the Sustainable Gas Institute (SGI) at Imperial College London in 2015 which studied methane and CO_2 emissions in from the gas supply chain. It reviewed the transparency, relevance and accuracy of over 400 papers to look at the methods used to calculate emissions and the factors that are creating such a large range (between 2 and 42 g CO_2 eq./ MJ HHV) in emissions estimates. This SGI report has provided the basis for this review which plans to examine and summarise this work alongside assessing how the topic has progressed since its publication. As this 2015 SGI report is considered a comprehensive synthesis of work regarding emissions in the gas supply chain, only literature produced since its publication has been reviewed in this study.

Overall, most data on emissions from the gas supply chain has come from the U.S with a lot of research having been conducted on methane emissions. This is due to industries having to satisfy the requirements of annual Inventory of United States Greenhouse Gas Emissions and Sinks (GHGI) required by the UNFCCC whereas other countries may have less stringent reporting requirements. Limited research has been carried out on CO_2 emissions in the natural gas supply chain with most work focusing on methane emissions. A standardised methodology on how to calculate emissions has yet to be developed and discrepancies still exist between ‘top-down’ and ‘bottom-up’ methodologies. This review is concluded by recommending future research needs and current data gaps (such as the above).

Contents

1. Introduction

The SGI published a report in 2015 "Methane and CO_2 Emissions from the Natural Gas Supply Chain" which was a comprehensive review intended to inform the debate on the magnitude and range of methane emissions across the gas supply chain. The report focusses on the methodologies behind current emissions estimations and the reasons for the range in estimates currently published. The SGI have established gaps in the current evidence and where further work is needed.

The 2015 SGI report systematically reviewed over 400 papers and it is considered a comprehensive review summarising the data available at the time on supply chain emissions. The paper predominantly focuses on methane emissions (as it comprises a majority of the data available, mainly from US projects). There is also limited discussion/ detail on how these emissions could be reduced other than making current methods more efficient (i.e. there is no discussion of the potential impact or costs of specific mitigation technologies).

The major conclusion to come from the report is that there is a large range in current estimates (the range of methane emission estimates is 0.2-10% of produced gas, although most lie within the 0.5-3% range). This is mainly controlled by the nature of the gas extracted (and hence processing requirements) but also the transportation routes needed. Fundamentally the report quotes "a central estimate of 496 g CO_2 eq. / kWh" which is "well below typical coal GHG estimates of around 1,000 g CO_2 eq. / kWh." It also emphasises that in terms of life cycle assessment the supply chain emissions will play a significant role and become proportionally significant as CCS is applied to the electricity generation process.

Since the publication of this SGI report more work has been conducted in the area although a majority of data is still centred on U.S methane emissions. A short literature search has seen the SGI cited in 4 peer reviewed journal papers, 2 looking at shale gas one on U.S air quality and another on decarbonising British electricity system (looking at a range of different power station types). Shale gas is at the forefront of a lot of climate debates and current research has focused on the potential impact of using shale gas rather than conventional sources, including a full supply chain analysis.

Two other papers were published at a similar time to the SGI report. The Joint Institute for Strategic Energy Analysis published a report in August 2015 on U.S methane emissions from the gas supply chain which came to similar conclusions as the SGI report. The World Resources Institute also published a report in June 2015 looking at how to reduce methane emissions from gas development, and was aimed at state-level policy makers. Other work has also been conducted from 2015 to now regarding emissions from the natural gas supply chain and is summarised in this report.

Overall, although a lot of work has been conducted to review current estimates there is no standardised method to conduct emissions estimates for the whole gas supply chain. As a result, the accuracy of these emissions estimates is still debated and a focus of current research. There are two main ways emission estimates can be conducted, using either 'top-down' or bottom-up' methods. Both methodologies are currently limited by a variety of factors which are discussed further within this review.

2. Summary of SGI Paper

The SGI report starts by introducing the different methodologies currently used to calculate emissions, then describing which emissions occur where within the supply chain and the metrics used to quantify emissions.

One difficulty in reviewing a variety of reports for comparison is the different ways in which emissions are quantified. Many studies will quote methane in cubic meters but levelised values are also stated in order to make comparisons between different fuels. As stated in the report, the following measurements can be used to refer to emissions:

- 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 methodologies used to calculate these values come under two main categories, either 'top-down' or 'bottom-up'. Bottom-up refers to when methane emissions are measured from a sample of sources at the emission point, then aggregated and extrapolated for a whole region or process. This is generally considered the more accurate method but data is difficult to acquire and requires thorough monitoring programs and data to be readily available. Top-down estimates are currently more regularly used and are calculated for a region by sampling atmospheric concentrations of methane and attributing the concentration to different activities. Inaccuracies arise from these calculations as it is difficult to attribute emissions to specific sources within the natural gas supply chain.

Emissions within the SGI report are categorised into the following potential processes:

- Combustion Emissions
  - → From the production of heat or electricity, usually from natural gas combustion. This usually results in CO_2 emissions but incomplete combustion can lead to methane release.

- Vented and flared emissions
  - → Can occur at carious point in the supply chain where CO_2 and methane must be vented. Where feasible this is normally captured in the oil and gas industry.

- Fugitive Emissions
  - → These are unintentional gas leaks that can occur at any time but are usually associated with the transportation of natural gas.

2.1 The Supply Chain

2.1.1 Exploration and pre-production

At this stage of the gas supply chain the characterisation of sites is carried out using seismic surveying and preliminary wellbore drilling. Economically viable gas wells are identified then the site is cleared and prepared for the necessary infrastructure e.g. roads and drilling platforms. Fracking may also be required at this stage for unconventional sources where fracking fluid is pumped into the well (along orders of magnitude of 10,000m^3). Once fracking is complete a 3-10 day period of 'flowback' is conducted where fluid alongside large slugs of gas return to the surface. The flowback gas must be treated prior to disposal. All wells must be completed which means they are cased, cemented and the well casing is perforated.

There is little information on emission sources linked to exploration activities. Emission sources will be energy use in equipment and transportation and possibly some small gas release. Most research has assumed emissions are negligible or are out of scope of the supply chain analysis. One report highlighted by the SGI (Santoro et al., 2011) estimated emission from site preparation and construction amount to approximately 1% of natural gas combustion emissions across a well's life. The energy consumption for an unconventional well will be larger given the pumping required. Generally pre-production emissions are considered low, 0.2-0.9 g CO_2 eq./ MJ HHV.

Well completion is a key greenhouse gas emitting stage (unlike other pre-production estimates) as 0-8.8 million m^3 of methane may be vented per completion. Emissions are both from venting and flaring. The main cause for variation is the well type, the equipment used and whether gas is flared, vented or collected. Emissions are much larger for unconventional wells given the flowback of hydraulic fluids.

2.1.2 Extraction

Extraction begins once the well is completed and downstream gathering equipment has been connected. The gas is collected from a variety of wells and using compressors and flow regulators it is gathered together using piping manifolds. Workovers may be conducted as pressure in the well drops with time, this may include further fracking, perforating different areas of the well or repairing leaks.

The largest emissions during extraction are likely to be from methane leaks and vents, with a small amount from combustion. Re-completion of wells tends to have emissions estimations similar to the original completion of the well.

During the lifetime of the well, flow may be hindered due to the build-up of liquids cause by pressure reduction in the gas flow preventing liquids being brought to the surface. If this occurs, liquid unloading may be required and can happen at any well (although it has been previously hypothesised this may be less likely for fracking wells this has now been proven to be untrue).

Liquid unloading is a major source of emissions during the extraction phase although data is currently lacking in depth and the emissions are often not accounted for in life-cycle assessments. The number of unloading events required for different wells can vary as well as the emissions from each event with events ranging from 0-7500 per year and 0-38,000 m^3 of methane per event. Current estimations are that 87% of wells will require liquid unloading within their lifetime but not during the early years of production. Whilst there are some large emitters, the distribution of emissions indicate most wells are located towards the lower end of the scale.

Generally there is very little data on CO_2 emissions associated with liquids unloading. The SGI stated the only measured data found was for the EPA Greenhouse Gas Reporting Program (GHGRP in 2015), 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.

2.1.3 Processing

After extraction raw gas must be processed to remove any contaminants (e.g. water, heavy hydrocarbons, CO_2, H_2S, nitrogen) and reach the gas sales specification. Often it is at this stage the gas is also compressed for the transmission pipeline. Water is removed via a glycol absorption column, heavy hydrocarbons are removed using an absorbing oil (then recovered by boiling off the butanes, pentanes etc.) and H_2S and CO_2 are removed using amine absorption.

There is a high uncertainty regarding emissions quantification from the processing stage. There are large ranges in quantities calculated but it is generally agreed that the largest source of emissions at the processing stage is from combustion emissions produced by compressors and reboilers. Emissions at this stage are therefore controlled by the composition of the extracted natural gas and the well pressure (e.g. how much treatment and compression are required). Although there is little data on how emissions vary with these factors.

Another large source of emissions at the processing stage is the CO_2 released during the CO_2 removal phase. The quantity release is dependent on the original composition of the natural gas but for a gas with a very high CO_2 composition, emissions could be as high as 50% of the processing emissions.

2.1.4 Transmission

Transmission pipelines operate at up to 100 bar(g) (gauge pressure, which is equivalent to absolute pressure minus atmospheric pressure) and gas can travel hundreds or thousands of kilometres. Regular compression stations are therefore required within the transportation pipeline.

Most data on emissions during transmission comes from Russia (with approximately 162,000km of pipeline) and the US (~485,000km) as they are the largest gas producers in the world. Emissions sources are from the gas fuelled compressors and potential methane leaks and vents across the transmission stage. Compressor seals and blowdown valves are considered to be one of the largest single emission sources with 0.5% of components accounting for 90% of emissions. Large variations in data may stem from the age and level of maintenance for different compressor stations. The length of pipeline is also important as compressor stations are required every 1000 km. Combustion emissions from compressors along the pipeline are also a main source of emissions.

2.1.5 Storage

Fluctuations in demand for gas create the requirement for it to be stored, which in most countries occurs underground. This is usually in depleted gas reservoirs, depleted aquifers or salt caverns. The term ‘base gas’ refers to the portion of gas stored that cannot be recovered which commonly occurs to a small amount of the gas stored. Storage may also cause the gas to be rehydrated and therefore require further processing. Because of this, storage site emissions are primarily from compressors and dehydration facilities with the main emissions source is considered to be from the compressor. Data prior to the SGI report had only taken into account methane emissions, there are no records of CO_2 emissions. An EPA study found that compressor venting accounted on average for 50% of site emissions.

2.1.6 Distribution

Domestic distribution begins at city gate stations where pressure is reduced (to around 25 bar(g)) and fed into a domestic consumer pipeline. The literature regarding emissions from distribution are generally focused on methane only, particularly looking at fugitive emissions at metering and regulating stations and distribution pipelines. The US distribution system is thought to account for approximately 20% of total emissions. An EPA report hypothesises that the greatest impact on reducing transmission elated methane emissions was to replace and eliminate unprotected metallic pipelines (vulnerable to corrosion) with plastic pipelines.

2.1.7 LNG Liquefaction, Storage and Distribution

As natural gas reserves can often be located large distances from consumers, in some areas it is compressed and shipped (rather than being transported solely by pipeline). To make the energy density higher and improve the efficiency of transportation, the gas is liquefied to form LNG (Liquefied Natural Gas). The liquefaction process involves cooling the gas to -160°C then maintaining that temperature and storing in cryogenic containers. Any impurities that may freeze (e.g. CO_2 and water) must be removed, meaning LNG is typically greater than 95% methane.

A lot of information regarding the emissions associated with LNG are not publicly available. Overall studies that estimate total supply chain GHG emissions tend to assume lower methane emissions than studies that do not incorporate LNG processes. The largest CO_2 emission source is the liquefaction process, with transportation emissions also dominated by CO_2. The size and operating efficiency of the tankers largely effects the transport related emissions. Methane leaks associated with venting and leaks in the transportation process are poorly accounted for.

The regasification process represents a much smaller contribution of emissions to the LNG supply chain. These are mostly as a result of CO_2 emissions from combustion for energy usage.

A summary of the estimated emissions at each stage in the supply chain (and their ranges) from the SGI report is shown in Figure 1 below:

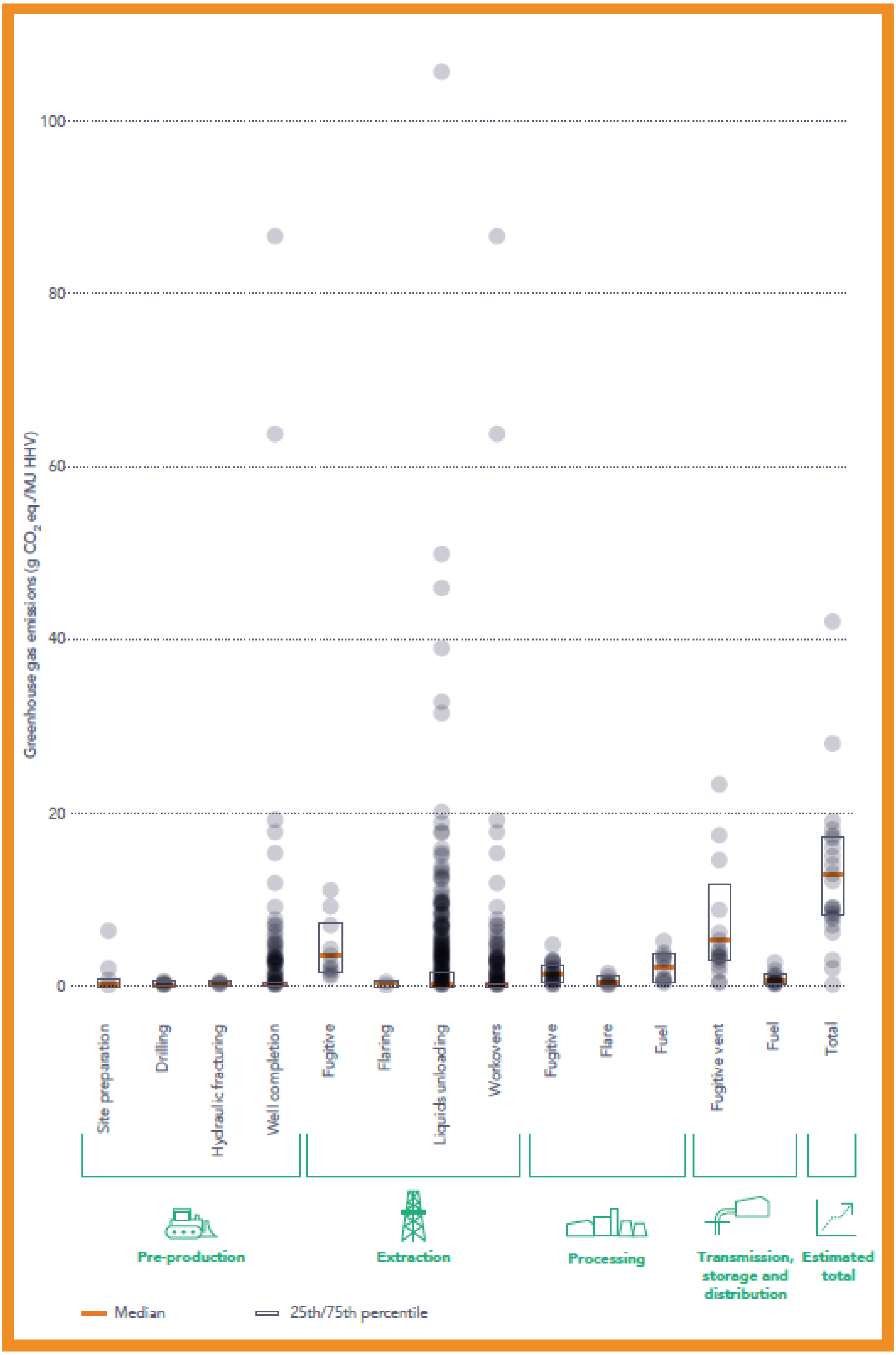

Figure 1: Greenhouse gas emission estimates across the natural gas supply chain. Each literature estimate of a supply chain stage is indicated as a grey circle. The median (orange), 25th percentile and 75th percentile (black box) estimate for each stage are shown with horizontal bars. Estimates of total supply chain emissions from individual studies are also shown. SGI, 2015

2.2 Discussion on the Range of Emissions Estimates

As shown in Figure 1, the range of emissions estimates can be large especially for specific processes such as well completion, liquid unloading and workovers. Within the SGI report these ranges are revised based on reviewing the data currently available and applying the research to modern well developed using best technologies and operational procedures. After conducting this analysis averages were significantly lowered e.g. for well completions the average emissions estimate was reduced from 86.6 to 0.3 g CO_2 eq./ MJ HHV. This was reduced based on the idea of reduced emission completion (RECs) being utilised. A full schematic of the revised estimates in shown in Figure 2:

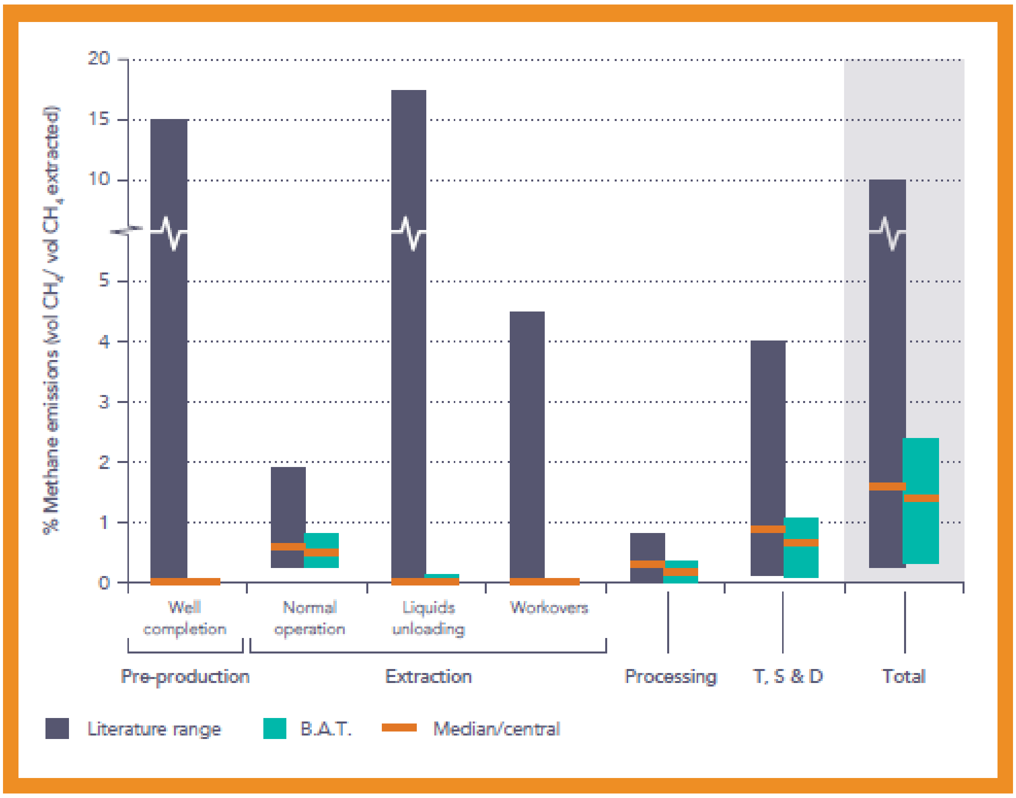

Figure 2: Summary of revised estimates. Revised emissions from fugitive and vented emissions compared to aggregated literature estimates. SGI, 2015

It is stressed in the report that clear outliers were removed and best practice operational procedures applied but that there had to be some 'human judgment' within this process. Generally the estimates are still considered 'conservative'. Moving forward the SGI report suggested that these emissions could be reduced even further beyond current best operational procedures.

The main two areas highlighted in the report for causing these large estimate ranges is the current lack of available data and the range of methodologies currently used to calculate emissions. Currently there is a lack of point source data that is s considered representative although a lot of greenhouse gas emission data has been collected. Offshore extraction emissions are a particular knowledge gap alongside data on coal bed methane, liquids unloading, transmission and storage leaks. Emissions across the gas supply chain are likely to be country specific dependant on environmental policy and legislation but currently a majority of data is focused on US emissions and hence is not globally comparable.

The methodologies used to calculate emissions still have their significant differences which is also a likely cause for the range in estimates. The main differences arise from the variations been top-down and bottom-up methods. There are also discrepancies between assumptions made e.g. for life cycle assessments the natural gas composition and assumed global warming potential for methane vary between studies.

2.3 Conclusions

The SGI report concluded that the range of methane emissions across the supply chain was from 0.2% to 10% of produced gas. This is equivalent to 58 g CO_2 eq./ MJ HHV. Accounting for both methane and CO_2, estimates range from 2 to 42 g CO_2 eq./ MJ HHV. This estimate was revised to a central average of 13.4 g CO_2 eq./ MJ HHV having reduced the current estimates to those feasible at best operational practice standards. The supply chain emissions were shown to contribute a significant proportion of emissions within the total life cycle of natural gas, and should CCS be employed supply chain emissions would increase proportionally.

Key emissions sources were identified as being from well completions, liquids unloading, pneumatic drivers and compressors. There was also evidence in the literature of a small number of gas facilities being 'super emitters'. Ineffective equipment, poor maintenance and poor operational procedures are the causes of these large emissions and could be significantly reduced should appropriate measures be taken.

The report concluded further work is required in the following areas:

- Further emission data is required especially from outside of North America. This would also allow insight into how regulatory practices have an impact from region to region on greenhouse gas emissions.
- Greater analysis to ascertain the mitigation potential at each stage of the supply chain and the potential emissions minimisation required for gas to contribute to low carbon energy systems.
- Research on how to improve 'super-emitting' facilities as this would have the greatest environmental impact.

3. Developments Since 2015

Since its publication in 2015, the SGI work has been cited in four papers published in peer-reviewed journals. An initial literature review shows the report has been referenced in numerous documents a summary of which is highlighted here. Since the SGI reports' publication, the increased extraction of unconventional gas sources globally has led to most work on this topic being related to calculating emissions from onshore unconventional gas extraction. Much of the current research focuses on methane emissions from the gas supply chain associated with fracking. When looking at the impact of fossil fuels on decarbonisation targets and air quality the emissions are often cited from the SGI report. A summary of selected papers published since 2015 studying the emissions from the natural gas supply chain is given below. These papers have been categorized either into research conducted on quantifying emissions (e.g. on developing methodologies or on regulations on how to quantify them) or research on how to reduce and mitigate emissions.

3.1 Quantifying Emissions

L. Höglund-Isaksson, 2017 - Bottom-up Simulations of Methane and Ethane Emissions from Global Oil and Gas Systems 1980 to 2012

This study developed a novel bottom-up approach for calculating methane and ethane emissions with the aim of comparing the results with top-down estimates calculated for the same time period. Emissions from 1980-2012 were quantified to help better explain the discrepancies between the two methodologies.

A full presentation of the steps taken to calculate the gas flow from every country in the world between the selected dates is included in detail in the report. One limitation of the data available was that most areas reported the sum of gas vented and flared but given methane emissions vary between the two techniques, quantification was difficult.

As stated in the SGI report top-down emissions estimates are often much larger than bottom-up methods. This report concluded that this bottom-up methodology quantified emissions much closer to top-down prediction. Oil was found to be a much larger producer than natural gas production. The variations in emissions over time were also studied and concluded that "the dramatic decline estimated for vented methane emissions from oil production following the fall of the Soviet Union, offers a possible explanation to the slowdown in the atmospheric methane concentration between 1990 and 2005 observed by top-down models". This most recent increases in methane emissions seen in top-down models were not accounted for in this report. Although unconventional gas extraction is increased the model predicted that this would be contracted by increased recovery of petroleum gas rather than emissions increasing.

The method used still had large uncertainties, as highlighted in the report. It was recommended that more data is required from countries globally on unintended leakages and venting ratios for unrecovered associated gas in order to better constrain current quantification estimates.

Boothroyd et al., 2015 – Fugitive Emissions of Methane from Abandoned, Decommissioned Oil and Gas Wells

This report studied the fugitive emissions from the well head during the production and storage stages of the gas supply chain, specifically looking at methane from decommissioned wells drilled into onshore UK hydrocarbon sites. The study looked at 66% of all properly decommissioned wells which covered 102 wells in four basins. The wells ranged from 8 to 79 years old.

Soil gas concentrations of methane were measured using a portable gas leak detector. Other factors were also taken into consideration such as well head location and humidity. Flux modelling was then conducted (using Fick's first law) with the given the soil gas measurements. Control sites were also tested for comparison.

The study concluded that 31 out of the 102 wells (30%) had elevated methane levels compared to the control group. There were also 39 wells that showed significantly lower methane gas soil levels than expected which demonstrated that some decommissioned sites had soil compositions that acted as a sink (e.g. due to oxidation). Overall the study summarised that the fugitive emissions for decommissioned sites is overall lower than if the sites were used for agricultural purposes. For reference, a well that had not been decommissioned had a CH_4 flux of 8604 kg CO_2eq/well/year.

The fugitive emissions of decommissioned wells were not discussed to in the SGI report which only referred to emissions during 'extraction phases'. This report concluded that "the modelled fluxes from the well sites suggest a mean fugitive emission of 364 ± 677 kg CO_2eq/well/year". Although this implies that emissions may be negligible in terms of the whole gas supply chain, this report only took into account sites which had been 'properly decommissioned' implying emissions from other sites could be higher if best practices are not followed.

Araiza et al., 2015 – Reconciling Divergent Estimates of Oil and Gas Methane Emissions

This study looked at the current discrepancies between estimates from top-down and bottom-up methods for methane emissions from the oil and gas sector. As discussed in the SGI report current calculations from top-down methods for methane emissions exceed those given from source based bottom-up approaches. This study looked at the Barnett Shale oil and gas region of Texas and conducted and compared both types of estimates.

The study developed a database using a co-ordinated campaign and managed to reduce the uncertainty in both types of estimates. After analysis reduced the uncertainties in the estimates both calculations agreed to within statistical confidence levels. This was achieved by reducing the uncertainty of top-down estimates using ethane fingerprinting to allow source attribution and using repeated mass balance measurements.

Elements that contributed to the convergence of the two estimates, were summarised as follows:

- The uncertainty associated with top-down approaches can be reduced by using a signature compound (e.g. ethane) to distinguish fossil fuel emissions from biogenic methane.
- Bottom-up estimates require accurate counts of all major sources. Under-estimates have occurred in other datasets due to the omission of facilities (e.g. high emitting compressor stations).
- The characterisation of facilities must focus on two things: 1. Being able to account for low probability but very high emitting sources. 2. Datasets must be integrated so that distributions accurately capture the magnitude and frequency of high-emitting sources.

The key factor that had contributed in the Barnett region to diverging results was that 2% of facilities were responsible for 50% of emissions (with 10% accounting for 90%) and these high-emitting sources need to be properly characterised. High-emitters were seen to be divided roughly equally among production sites, compressors, and processing plants. Future work is needed to understand the characteristics that cause an individual site to be a high-emitter.

JISEA, August 2015 - Estimating U.S Methane Emissions from the Gas Supply Chain

The Joint Institute of Strategic Energy Analysis wrote a report in August 2015 (a month before the SGI report) studying the approaches and estimates used to calculate U.S methane emissions from the natural gas supply chain. It is similar to the SGI report discussing where the ranges in calculations come from and how methodologies vary from top-down to bottom-up estimates. This report was written to better inform the annual U.S GHGI (inventory of greenhouse gas emissions and sinks, as required by the UNFCC) and concluded that none of the methods currently available would be considered a ‘standard’ for calculating gas supply chain emissions.

One conclusion from the report is that a majority of emissions downstream of production are from compressor stations (contributing 43% of total emissions across the supply chain and being the main emitter during the processing stage). The study also estimated that during distribution fugitive emissions were dominant and could be reduced by replacing cast iron and unprotected steel pipeline with plastic and protected steel. These conclusions are similar to those of the SGI report, the largest emitters in both reports are both considered to be compressors.

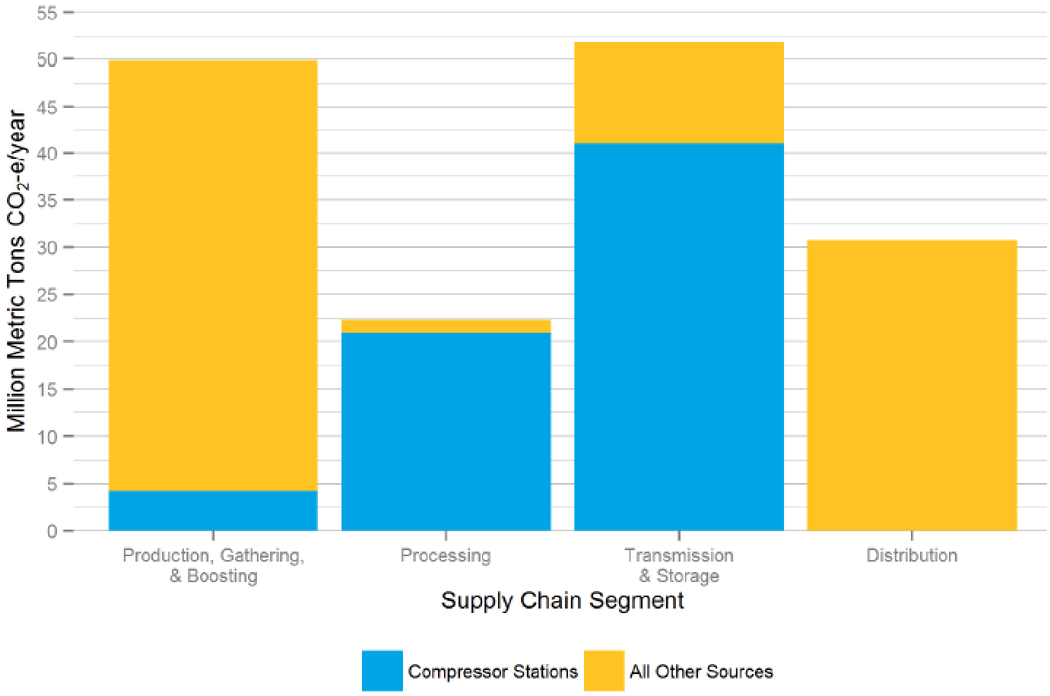

Figure 3: U.S. GHGI estimates of methane emissions. From natural gas compressors within each supply chain segment in 2012. JISEA report, 2015.

The report made recommendations on how to improve top-down and bottom-up studies and then how to integrate the two. The report suggested that bottom-up studies are beneficial for filling known gaps in emissions source data such as abandoned wells. A key limitation for top-down measurements are the difficulties in attributing emissions to their sources. Alongside the attribution process, more research is also required to distinguish emissions from non-oil and gas sources, e.g. natural seepages. Combining the two methods could significantly improve the current gap between measurements and inventories but is currently difficult given their different temporal and spatial scales.

Adam Brandt from Stanford University was an author for the JISEA paper and also on expert advisory panel for the SGI report. Although this JISEA paper is not referenced in the SGI report the conclusions in both are likely to be driven by the same literature analysis and data collection.

3.2 Mitigation and Reduction of Emissions

Gambhir et al., 2017 - The Contribution of Non-CO_2 Greenhouse Gas Mitigation to Achieving Long-Term Temperature Goals

This report studied the impact that reducing non-CO_2 greenhouse gases would have on the cost of climate change mitigation compared to just reducing CO_2 alone. To reach a 2.5°C target by 2100 the study predicted a cost of $48 trillion if only CO_2 was reduced. If non-CO_2 greenhouse gases were also reduced alongside this, the targets could be reached with a cost of $17 trillion. This is a reduction from about 1.6% of cumulative discounted GDP over the period 2010–2100 to 0.6% of GDP.

The GAINS (Greenhouse Gas Air Pollution Interactions and Synergies) model was used to estimate non-CO_2 GHG sources and TIAM-Grantham (Grantham Institute's TIMES Integrated Assessment Model) to model CO_2 emissions.

The source and mitigation options used in the models for non-CO_2 greenhouse gases are summarised using a table in the report where methane contributed 20% of total non-CO_2 greenhouse gases in the model. Fugitive emissions from gas extraction, transmission and distribution were included as a source of methane (alongside livestock, wastewater, rice cultivation and crop residue burning). Mitigation options for fugitive emissions from the gas supply chain were listed as reduced venting and leakage control (from the well and transmission/distribution). No details are included on how to conduct these methane reductions or how much each individual technology may potentially cost.

The report highlights that including non-CO_2 gas reductions in mitigation scenarios could reduce costs of achieving them through CO_2 reduction alone. It concludes "further research into the drivers, barriers and costs of mitigating these gases" is required so that "policy makers can understand the trade-offs between early, gradual and delayed adoption of non-CO_2 mitigation measures". Generally the mitigation options for non-CO_2 gases remain relatively less well explored compared to CO_2 options.

Nguyen et al., 2016 – CO_2 Mitigation Options for the Offshore Oil and Gas Sector

This study looks at the mitigation of CO_2 emissions from the oil and gas sector, specifically at offshore extraction. Three mitigation technologies are looked at in particular:

- Waste heat recovery;
- CO_2 capture;
- Platform electrification.

A North Sea oil platform is used as a case study to model, analyse and compare these three mitigation options using thermodynamic, economic and environmental indicators. Results showed that using all three emissions could be reduced by more than 15% although costs would be site specific varying widely dependant on natural gas price and CO_2 tax.

Waste heat recovery technologies (e.g. steam Rankine cycles) are currently at a mature stage for onshore use but have only been used on 3 facilities offshore. In all scenarios modelled the integration of a steam network was profitable with greater gas export of up to 16%.

This study focused on pre and post-combustion technologies for CO_2 capture as they are the most mature. The study concluded that the capture process is technically feasible but the economic trade-off between power production and reduction in CO_2 emissions depends on the value of CO_2-tax, the economic field lifetime and the natural gas market price. All of these will impact the profitability of using CO_2 capture.

The cost of platform electrification is controlled by the distance from shore (i.e. the electricity supply distance). For this study, two supply scenarios were considered: firstly, where all power demand is met by supply on land but heating demand is met by natural gas combustion (which is likely for offshore settings); secondly, all power is supplied from shore and heating demand is met by electric heating (which will occur if heating demand is small). The study concluded that electrification was beneficial both from a thermodynamic and environmental perspective. This is because onshore power plants have higher efficiencies than gas turbines installed on offshore platforms. The CO_2 emissions associated with electrification depend on the production source onshore i.e. gas-fired combined cycle power plants or renewable facilities.

Overall the study proved that each mitigation technology was beneficial and could be competitive economically in the future. Economic incentives are still required to enable the development of energy efficient and environmentally friendly solutions.

WRI, June 2015 – Reducing Methane Emissions from Natural Gas Development

The working paper published by the World Resources Institute (WRI) in June 2015 (before the SGI report's publication) looks at the implications of the increased extraction of natural gas in the U.S and its impacts on emissions targets. The paper includes policy recommendations and best practices aimed at reducing emissions from key sources in the natural gas system.

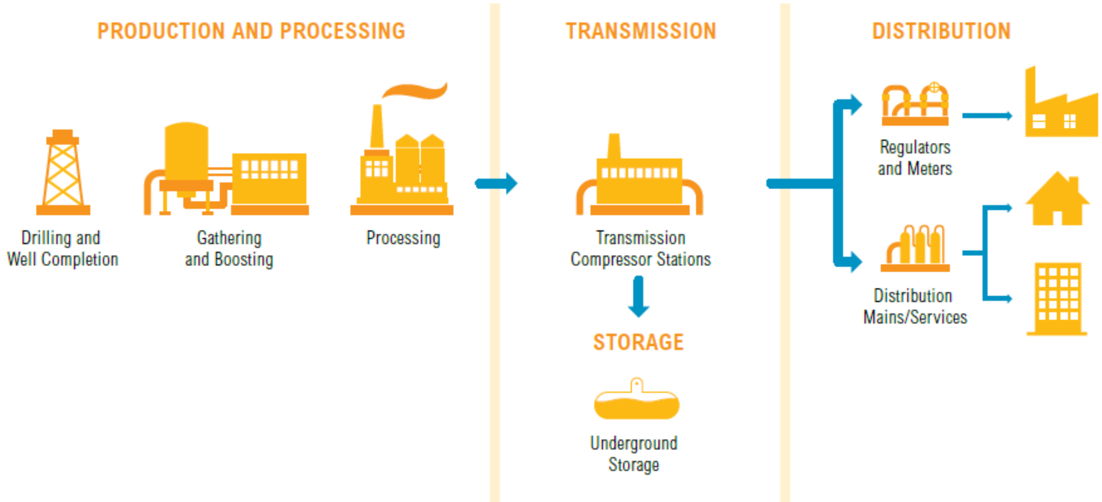

Figure 4: The natural gas supply chain. Schematic summary of the whole supply chain as presented in the World Resources Institute June 2016 paper.

As in the JISEA and SGI report, compressors and equipment leaks are considered the biggest sources (both approximately 19% of emissions from the natural gas system). For compressors it is recommend in the paper to replace rod packing systems every three years and require annual maintenance to ensure good working order. For static components is also recommended that there is regular leak detection and repair at processing plants and gathering lines. To address equipment leaks the report suggests that states should require two-stage leak detection and repair for all production facilities, processing plants, compressor stations and above/below ground distribution facilities. Leaks should be repaired within 5 working days and companies should report the results of mobile monitoring surveys to the state.

Emission reduction opportunities during the processing stage predominantly come from improving the centrifugal compressors and gas burning engines. The main source of methane emissions from centrifugal compressors comes from the leakage of methane from seals around the rotating shaft. Wet seals have been found to leak considerably more than dry seals (as the oil used absorbs pressurised gas, which in then later vented). The EPA's 2012 performance standards require modified wet seals which will reduce methane emissions but these standards do not apply to existing compressors. Current predictions are that 85% of emissions from current compressors come from wet seals. Other leaks (e.g. from valves) may also occur at the compressors stage, and hence comprehensive monitoring and detection programs are also recommended in the paper. Gas-burning engines are present throughout the natural gas supply chain and are a significant source at the processing stage. Using an electric motor instead of gas engines would avoid methane emissions altogether. Chemical methods exist for reducing air pollution associated with engine exhausts but do not prevent methane from venting to the atmosphere.

Pipeline venting is considered a major emissions source during the transportation stage (alongside compressors as previously discussed). Venting usually occurs during pipeline maintenance by operator where the pressure must be reduced and often the gas removed from section of pipeline. This paper suggest others methods for reducing pipeline pressure which does not involve direct gas venting. During emergency maintenance in-line compressors can pump-down the gas moving enough gas down the pipeline to reduce the pressure in the required section to a safe level. This can reduce emissions by 50% from venting alone. If portable compressors are used to reduce pressure even further this could even be increased to 90%.

Many distribution lines delivering natural gas to households are old and leaky as they are primarily constructed of cast iron and unprotected steel. The aging of these pipelines since their installation (usually early 1900s) has led to considerable leakages. Most areas in the U.S are currently undertaking a transition of the pipeline network to reduce leakage incidents by using plastic or protected steel. Although it is not mentioned in this report the The Environmental Defense Fund (EDF) are currently conducting a project measuring NG leaks in urban distribution networks. They have equipped a Google Street View car with methane sensors. Further details of the emissions monitoring work can be found on their website (https://www.edf.org/climate/methanemaps) but overall the produced maps highlight the improvements to leakage reduction made when investing in new infrastructure.

The paper concluded that natural gas could play a part in meeting climate targets but only if methane emissions are kept under control. The technologies to control emissions at each stage of the gas supply chain are available and emission standards need to be driven by the government, public and stakeholders to make sure the best practices outlined in the working paper are meet.

Committee on Climate Change, 2016 – Onshore Petroleum - The Compatibility of UK Onshore Petroleum with Meeting the UK's Carbon Budgets

In March 2016 the Committee on Climate Change published a report looking at "the compatibility of UK onshore petroleum with meeting the UK's carbon budgets". This report was produced for presentation to parliament pursuant to Section 49 of the Infrastructure Act 2015 and in summary advised the government that on a significant scale shale gas would not be consistent with the UK carbon budgets and 2050 target (unless large emission reductions are made). The SGI's work on supply chain emissions was regularly cited in the report when looking at predicted emissions from individual sources.

The report looked at how regulation could impact the greenhouse gas emissions from shale gas production and showed that comprehensive regulation could allow a large reduction in emissions. Four cases for potential regulations were constructed and described as no regulations; current UK position; minimum necessary regulations and full technical mitigation options. The report concluded that under central estimates, the current UK position saves 19% of emissions (relative to having no regulations) and 46% savings under the 'Minimum necessary regulation' case and 62% under the 'Further Technical Mitigation Options' case. This is shown in Figure 5 (below).

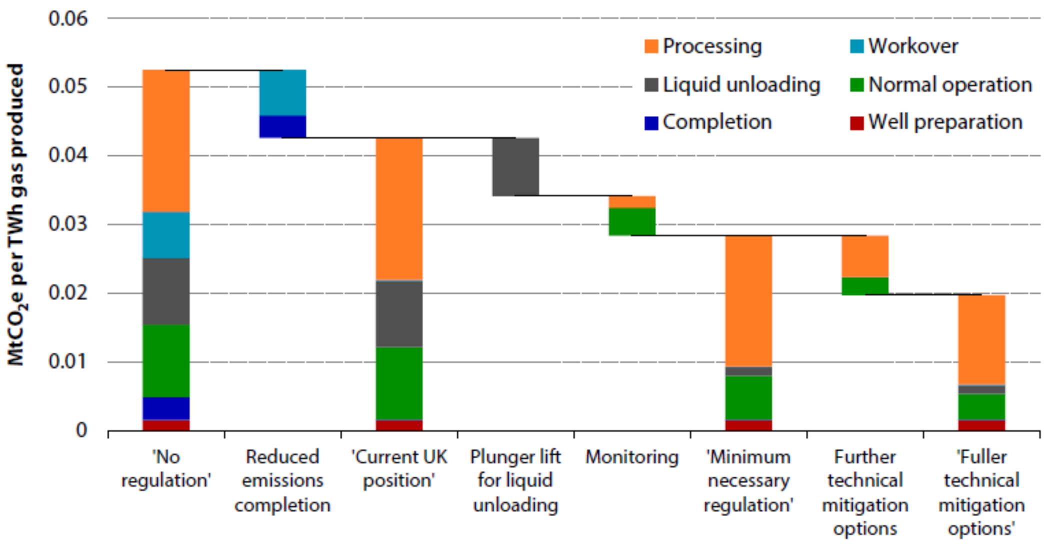

Figure 5: Differences between the Regulation Cases under Central Estimates. Figure showing emissions and their sources/stages in the gas supply chain in relation to potential regulation. Committee on Climate Change, 2016.

The report outlines three 'tests' which must be met in order for shale gas extraction to meet

UK emissions targets:

1. Well development production and decommissioning emissions must be strictly limited.
2. Gas consumption must remain in line with carbon budgets (i.e. shale gas should reduce gas imports rather than increasing domestic consumption).
3. The increase in emissions from shale gas must be offset somewhere else within the UK economy.

The storage and transportation of gas were not studied in terms of emissions within the report.

Environment Protection Agency, September 2013 – Global Mitigation of Non-CO_2 Greenhouse Gases: 2010-2030

This report was published before the SGI analysis but remains one of the few studies to review the costs of various potential mitigation technologies by conducting an engineering cost analysis. This report studies non-CO_2 emissions but gives details on potential reductions of methane from oil and natural gas systems. The report summarises that most abatement measures fall into three categories:

- Equipment modifications/ upgrades
- Changes in operational and maintenance practices (including direct inspection and maintenance)
- Installation of new equipment

The report highlights that "voluntary programs such as the Global Methane Initiative (GMI) and USEPA's Natural Gas STAR Program, which are aimed at identifying cost-effective CH_4 emission reduction opportunities, have developed a well-documented catalog of potential CH_4 abatement measures that are applicable across the segments of the ONG system". This particular study is based on the STAR program's system. A summary of abatement measures and predicted costs is given in Appendix A and brief summaries of some of the technologies described in the report are given below.

For the production section of the oil and natural gas supply chain the two abatement methods highlighted in the report are installing vapour recovery units (VRUs) and reducing emissions for hydraulically fractured natural gas well completions (REC). The REC method is designed to capture 90% of gas during new well constructions that are hydraulically fractured. The emissions would otherwise be flared or vented and the equipment consists of a sand trap, separator and gathering line. Recovered gas and condensate can then be sold, reducing costs. VRUs are utilised to capture 95% of light hydrocarbon vapour emissions from crude oil and condensate tanks which are otherwise vented to atmosphere. These recovered vapours can then be sold or used on site as fuel.

Directed inspection and maintenance (DI&M) on processing plants and booster stations was emphasised in the study for being the most cost-effective method for mitigating emissions from the gas processing and transmission segments. Identifying and replacing high-bleed pneumatic devices was also discussed as it can reduce emissions by 50-90%. Reducing emissions from compressor rod packing systems can also be achieved by avoiding unwanted gas leakage by having a correct fit and alignment of packing parts. The report describes replacing wet seals with dry seals and was highlighted as a key emission mitigation method, as also discussed in the SGI report.

Direct inspection and maintenance at gas stations and surface facilities was also suggested as an emissions mitigation method for the gas distribution segment of the gas supply chain. A significant source of emissions are leaking meters, pipes, valves, flanges and fittings and DI & M is a cost-effective way of minimising equipment leaks.

A marginal abatement cost analysis is outlined in the report with the methodological approach full detailed. A summary of the results are included in Appendix A.

Improved information on the distribution of emissions in international baselines was considered one of the main uncertainties associated with the costs modelled in the report. More information is required on how oil and gas baselines are changing over time as the calculations used in the EPA report are based on historical activity factors.

Citations of the SGI Report

The SGI report has been directly cited in 4 papers published in peer review journals. None of these papers directly look at natural gas supply chain emissions but make use of figures quoted in the report.

The first was published in March 2016 by D. Allen looking at the impact of emissions on U.S air quality and was published in the Journal of the Air Quality and Waste Management Association. The paper does not research natural gas supply chains but refers the SGI report when stating the emissions of natural gas need to be taken into account.

A second paper published by Hammond and Grady in March 2016 (Applied Energy) studied the energy assessment of UK shale extraction. The SGI was quoted on the total GHG emissions associated with full chain gas emissions. It was highlighted that a drawback of this report was that no individual figures were present for unconventional versus conventional sources and a disaggregation of this information would be beneficial.

Another paper focused on the decarbonisation of the UK energy system and was published by Iain Staffell in Energy Policy, 2017. The report discussed that taking into account life-cycle emissions of fossil fuels could increase their carbon intensity by 7-10% referencing the SGI report. It highlighted that supply chain emissions are important and must be taken into account when looking at decarbonising the UK.

Another paper published in 2017 was by Few et al. (printed in Energies) and studies the impact of shale gas on meeting climate targets. To make the point that conventional wells still have upstream methane leakages and the research has implied that "higher production-normalised emissions rates in conventional gas extraction sites than shale gas extraction sites in the Marcellus region" had been identified.

4. Summary

The SGI report concluded that methodologies for quantifying methane emissions needed standardising and currently were not sufficient. The estimation ranges found in their study were large and reductions in uncertainties were required to improve quantification. Estimations from top-down methods were currently much higher than those attributed to sources by bottom-up methods. It was concluded that for successful mitigation bottom-up methods were required but these need to be improved by the acquisition of more refined data from a larger number of countries.

Since 2015 the knowledge base on how to quantify emissions has been added to by numerous reports. Notably, the divergent estimates calculated by bottom-up and top-down methods have been reduced. There is still an emphasis across all studies that more data is required to improve the accuracies of methods but methods have also been improved. For top-down methods source attribution using isotopes to identify whether methane is from fossil fuels or biogenic has been successful and helped reduce estimates to coincide with bottom-up estimates. The SGI report highlighted that a focus on super-emitters and calculating emission from major sources was required to improve bottom-up estimates but no work seems to have developed this further since 2015.

A key element following on from the SGI work was how to mitigate the sources along the gas supply chain once they had been identified. The greatest mitigation potential was identified at 'super-emitter' sources where emissions could be reduced dramatically. Limited in depth work has been published in this area since 2015 with most focussing on how compatible unconventional sources are for various climate targets and that mitigation will be required. The specific research on how this will be conducted, how much emissions can be reduced and at what part in the supply chain this can occur is still not available.

5. IEAGHG Recommendations for Future Work

Prior to the publication of the SGI report in 2015, the IEAGHG intended to conduct a study into how to reduce CO_2 emissions from the natural gas supply chain. Elements of the scope were comprehensively covered by the SGI report but some areas of outstanding research remain. From this initial literature review, recommendations for future work include:

- Further work is required on CO_2 emission estimates:
    - Most work to date has focused on reviewing methane emissions the supply chain (given U.S regulations to report methane releases) but there is limited data on CO_2 emissions.
    - Quantification of potential CO_2 release at each point in the gas supply chain would be beneficial.
    - Future analysis could also include both direct and indirect CCS (e.g. by using electricity from off-site CCS plants instead of gas turbines to drive pipeline compressors) and the implications for emissions reduction in the gas supply chain.

- Further work is required on how to reduce emissions:
    - Numerous solutions to large emissions sources have been suggested throughout the literature such as improving equipment efficiencies but more work is required to outline the costings of undertaking these emissions reductions.
    - An in depth review into each potential reduction technique would be beneficial. This would include estimated individual costings for each technique and the potential emissions reductions achievable. This would add to the work of the 2013 EPA report on non-CO_2 emissions which stated more baseline data was required.
    - A cost-benefit analysis should include the sensitivities and significant criteria which may vary between sites. Overall, a cost-supply curve for CO_2 (and methane) emissions reduction from the natural gas supply chain should be estimated.
    - The timescales to commercial availability of new emission reduction technologies is also required.

- More work is also required on emissions due to flaring, to further study best practices and alternatives. Flaring emissions from the associated oil well were not included in the SGI report but are a major source of methane emissions.
    - The Global Gas Flaring Reduction Partnership (GGFR) announced their "Zero Routine Flaring by 2030" program in June 2017 and will contribute to flaring mitigation methods work in the future.
    - Previous GGFR work includes reports on how to recover and monetize flared emissions or associated gas. These are available on their website.

- Bottom-up calculations will also need further development to improve the accuracy of emission estimates, in particular calculating the emissions from potential 'super-emitters'. Most studies have concluded that top-down calculations are too difficult to attribute specific sources too and therefore make studying the gas supply chain at individual points difficult (although ethane fingerprinting has improved estimates).

- Long-term analysis is still required on how gas supply chains are likely to progress in the future, e.g. use of liquefied natural gas (LNG), long-distance pipelines and gases with high CO_2 concentrations. More recent work has been focusing on the implications of the increased use of shale gas but more research is required into longer term predictions. (IEAGHG are currently undertaking a techno-economic assessment of CO_2 capture in LNG plants and have published a study on CO_2 capture with PSA in NG production.)

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Appendix A

Abatement Measures and Engineering Cost Analysis

Tables from Environment Protection Agency; *Global Mitigation of Non-CO_2 Greenhouse Gases, 2010-2030;* Office of Atmospheric Programs; September 2013

Table 2-3: Abatement Measures Applied in Oil and Gas Production Segments

Abatement Measure	Component	Total Installed Capital Cost ($2008)	Annual O&M ($2008)	Time Horizon	Technical Effectiveness[a]
Directed Inspection & Maintenance at Gas Production Facilities	Chemical Injection Pumps	—	6,675	1	40%
Installing Surge Vessels for Capturing Blowdown Vents	Compressor BD	158,940	28,078	15	50%
Installing Electronic Starters on Production Field Compressors	Compressor Starts	2,649	5,849	10	75%
Directed Inspection & Maintenance at Gas Production Facilities	Deepwater Gas Platforms	—	50,000	1	95%
Install Flash Tank Separators on dehydrators	Dehydrator Vents	6,540	—	5	30% to 60%
Optimize glycol circulation rates in dehydrators	Dehydrator Vents	—	15	1	33% to 67%
Installing Catalytic Converters on Gas Fueled Engines and Turbines	Gas Engines - Exhaust Vented	7,924	4,374	10	56%
Installing Plunger Lift Systems in Gas Wells	Gas Well Workovers	5,646	(13,855)	5	80%
Replace Gas-Assisted Glycol Pumps with Electric Pumps	Kimray Pumps	2,788	1,949	10	100%
Directed Inspection & Maintenance at Gas Production Facilities	Non-associated Gas Wells	—	817	1	95%
Installing Plunger Lift Systems in Gas Wells	Non-associated Gas Wells	5,646	(13,855)	5	80%
Directed Inspection & Maintenance on Offshore Oil Platforms	Offshore Platforms, Deepwater oil, fugitive, vented and combusted	—	50,000	1	43%
Flaring Instead of Venting on Offshore Oil Platforms	Offshore Platforms, Shallow water Oil, fugitive, vented and combusted	165,888,859	4,976,666	15	98%
Installing Vapor Recovery Units on Storage Tanks	Oil Tanks	473,783	161,507	15	58%
Using Pipeline Pump-Down Techniques to Lower Gas Line Pressure Before Maintenance	Pipeline BD	—	1,352	1	90%
Directed Inspection & Maintenance at Gas Production Facilities	Pipeline Leaks	—	82	1	60%
Convert Gas Pneumatic Controls to Instrument Air	Pneumatic Device Vents	72,311	24,321	10	50% to 90%
Replacing High-bleed Pneumatic Devices in the Natural Gas Industry	Pneumatic Device Vents	165	—	10	8% to 17%

Table 2-3: Abatement Measures Applied in Oil and Gas Production Segments (continued)

Abatement Measure	Component	Total Installed Capital Cost ($2008)	Annual O&M ($2008)	Time Horizon	Technical Effectiveness[a]
Directed Inspection & Maintenance at Gas Production Facilities	Shallow water Gas Platforms	—	33,333	1	95%
Reduced Emission Completions for Hydraulically Fractured Natural Gas Wells	Unconventional Gas Well Completions	—	30,038	1	90%
Reduced Emission Completions for Hydraulically Fractured Natural Gas Wells	Unconventional Gas Well Workovers	—	30,039	1	90%
Installing Surge Vessels for Capturing Blowdown Vents	Vessel BD	158,940	28,078	15	50%
Installing Plunger Lift Systems in Gas Wells	Well Clean Ups (LP Gas Wells)	5,646	(13,855)	5	40%

[a] Technical effectiveness reflects the percentage reduction achievable from implementing the abatement measure considering the presence of complementary options. Technical effectiveness is the product of three separate factors—the reduction efficiency, technical applicability, and market penetration.

[b] Lower technical effectiveness is due to limited applicability at LP gas wells.

Table 2-4: Abatement Measures for the Natural Gas Processing Segment

Abatement Measure	Component	Total Installed Capital Cost ($2008)	Annual O&M ($2008)	Time Horizon	Technical Effectiveness[a]
Installing Surge Vessels for Capturing Blowdown Vents	Blowdowns/Venting	158,940	28,078	15	50%
Directed Inspection & Maintenance at Processing Plants and Booster Stations - Compressors	Centrifugal Compressors (dry seals)	—	15,581	1	12%
Directed Inspection & Maintenance at Processing Plants and Booster Stations - Compressors	Centrifugal Compressors (wet seals)	—	6,131	1	12%
Replacing Wet Seals with Dry Seals in Centrifugal Compressors	Centrifugal Compressors (wet seals)	380,804	(102,803)	5	66%
Installing Catalytic Converters on Gas Fueled Engines and Turbines	Gas Engines - Exhaust Vented	7,924	4,374	10	56%
Replace Gas-Assisted Glycol Pumps with Electric Pumps	Kimray Pumps	2,788	1,949	10	100%
Directed Inspection & Maintenance at Processing Plants and Booster Stations	Plants	—	10,134	5	95%
Directed Inspection & Maintenance at Processing Plants and Booster Stations - Compressors	Recip. Compressors	—	6,131	1	10%
Early replacement of Reciprocating Compressor Rod Packing Rings	Recip. Compressors	7,800	0	5	1%
Fuel Gas Retrofit for BD valve - Take Recip. Compressors Offline	Recip. Compressors	2,365	—	5	21%
Reciprocating Compressor Rod Packing (Static-Pac)	Recip. Compressors	5,696	—	5	0%

[a] Technical effectiveness reflects the percentage reduction achievable from implementing the abatement measure considering the presence of complementary options. Technical effectiveness is the product of three separate factors: the reduction efficiency, technical applicability, and market penetration.

Table 2-5: Abatement Measures for the Natural Gas Transmission Segment

Abatement Measure	Component	Total Installed Capital Cost ($2008)	Annual O&M ($2008)	Time Horizon	Technical Effectiveness[a]
Directed Inspection and Maintenance at Compressor Stations - Compressors	Centrifugal Compressors (dry seals)	—	15,581	1	13% to 14%
Replacing Wet Seals with Dry Seals in Centrifugal Compressors	Centrifugal Compressors (wet seals)	380,804	(102,803)	5	71% to 77%
Install Flash Tank Separators on dehydrators	Dehydrator Vents	9,504	—	5	67%
Optimize glycol circulation rates in dehydrators	Dehydrator vents	—	15	1	67%
Installing Catalytic Converters on Gas Fueled Engines and Turbines	Engine/Turbine Exhaust Vented	7,924	4,374	10	56%
Directed Inspection and Maintenance at Gate Stations and Surface Facilities	M&R (Trans. Co. Interconnect)	—	1,741	1	72%
Directed Inspection and Maintenance on Transmission Pipelines	Pipeline Leaks	—	41	1	60%
Using Pipeline Pump-Down Techniques to Lower Gas Line Pressure Before Maintenance	Pipeline venting	—	1,352	1	90%
Convert Gas Pneumatic Controls to Instrument Air	Pneumatic Devices	72,311	24,321	10	50% to 90%
Replacing High-bleed Pneumatic Devices in the Natural Gas Industry	Pneumatic Devices	165	—	10	8% to 17%
Directed Inspection and Maintenance at Compressor Stations - Compressors	Recip Compressor	—	15,581	1	10% to 12%
Early replacement of Reciprocating Compressor Rod Packing Rings	Recip Compressor	7,800	—	5	1%
Early replacement of Reciprocating Compressor Rod Packing Rings and Rods	Recip Compressor	41,068	—	5	1% to 74%
Fuel Gas Retrofit for BD valve - Take Recip. Compressors Offline	Recip Compressor	2,365	—	5	36% to 39%
Reciprocating Compressor Rod Packing (Static-Pac)	Recip Compressor	5,696	—	5	6% to 9%
Installing Surge Vessels for Capturing Blowdown Vents	Station venting	158,940	28,078	15	50%
Directed Inspection and Maintenance at Compressor Stations	Stations	—	1,398	1	85%
Directed Inspection and Maintenance at Gas Storage Wells	Wells (Storage)	—	651	1	95%

[a] Technical effectiveness reflects the percentage reduction achievable from implementing the abatement measure considering the presence of complementary options. Technical effectiveness is the product of three separate factors: the reduction efficiency, technical applicability, and market penetration.

Table 2-6: Abatement Measures for the Distribution Segment

Abatement Measure	Component	Total Installed Capital Cost ($2008)	Annual O&M ($2008)	Time Horizon	Technical Effectiveness[a]
Directed Inspection and Maintenance at Gate Stations and Surface Facilities	M&R <100	—	1,604	1	30% to 80%
Replace Cast Iron Pipeline	Mains—Cast Iron	373,633	182	5	95%
Replace Unprotected Steel Pipeline	Mains—Unprotected steel	373,633	182	5	95%
Replace Unprotected Steel Service Lines	Services—Unprotected steel	418,023	311	5	95%

[a] Technical effectiveness reflects the percentage reduction achievable from implementing the abatement measure considering the presence of complementary options. Technical effectiveness is the product of three separate factors: the reduction efficiency, technical applicability, and market penetration.

Evaluating technology options to mitigate greenhouse gas emissions

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