2 CSG Production Technology

2.1 Differences between CSG and Other Unconventional Gas Production

The technology and practices employed in gas production can affect the level of fugitive emissions released. Recent estimates of fugitive emissions from unconventional gas have been based on shale gas or tight gas occurrences in the U.S. but substantial differences exist between the production methods used for these and those used in the Australian CSG industry. Consequently there may also be differences in fugitive emissions from different unconventional gas sources. Some of the main differences between the various production methods are summarised in Table 2.1.

Table 2.1. Key differences between CSG, shale gas and tight gas

	CSG	Shale Gas	Tight Gas
Source Rock	Coal seams	Low permeability fine grained sedimentary rocks	Various source rocks have generated gas that has migrated into low permeability sandstone and limestone reservoirs.
Depth	300-1000 m	1000-2000+ m	> 1000 m
Gas Occurrence	Physically adsorbed on coal organic matter	Stored within pores and fractures but may also be adsorbed on organic matter.	Within pores and fractures.
Gas Composition	Usually > 95 % methane. Small amounts of CO_2 and other gases may be present.	Mostly methane but may also contain significant quantities of higher hydrocarbons (condensate).	Mostly methane.
Extraction Technology	This is described in Section 2.3. Hydraulic fracturing is sometimes required. Currently less than 10 % of wells in Australia require this treatment but this may increase as lower permeability seams are targeted.	Hydraulic fracturing and horizontal wells are usually necessary.	Large hydraulic fracturing treatments and/or horizontal drilling are required.
Water Usage	Water must be pumped from seams to reduce reservoir pressure and allow gas to flow. If hydraulic fracturing is necessary, water is required for the fracturing process.	Water is required for hydraulic fracturing	Water is required for hydraulic fracturing.
Extraction Challenges	Removal of seam water and	Overcoming low	Reducing infrastructure

	its subsequent disposal.	permeability. Minimising the amount of water required for hydraulic fracturing. Reducing infrastructure footprint.	footprint.

2.2 Exploration

Exploration wells are used to estimate the amount of gas present (gas in place) and involve drilling to recover core samples that are used to determine gas contents and compositions. Since reservoir pressure is not drawn down in this process, fugitive emissions from reservoirs will be small because most seam gas is stored by adsorption within the coal rather than as free gas. Consequently, gas is not released until the reservoir pressure is reduced.

Production pilot testing is another exploration activity and pilot wells differ from exploration wells in that they are used to assess gas production rates. These pilots involve a cluster of up to about five wells which are put into operation for a period long enough to ascertain likely production behaviour. Generally these production pilots are distant from existing production infrastructure and therefore the gas produced cannot be used commercially. It may be used to power production equipment or alternatively flared or vented. The Queensland Petroleum and Gas Act 2004 requires that gas should be used commercially wherever possible or flared if it is not. Venting gas is only allowed when flaring is not technically possible or for safety reasons. Regulatory approval is required for each well where flaring or venting will be for more than 30 days and approval can cover periods up to 13 months.

2.3 Production

Production of CSG typically involves many more wells than that for conventional reservoirs. Wells are drilled progressively over the life of the reservoir; as production declines in old wells and these are abandoned, new wells are drilled as replacements to meet the required production rate from the field. Therefore the process of drilling new wells and abandoning old wells continues throughout the life of the field.

2.3.1 Drilling and Completion of Production Wells

Drilling

Drilling of wells is a major activity in developing a CSG production field. The potential for fugitive releases of methane during this process will be greater if there is free gas within the reservoir, although wells are drilled with blow-out preventers which avoid uncontrolled gas release during drilling. Typically, in their virgin state, there is no free gas within coal seam reservoirs as the gas is stored by adsorption under pressure due to the head of water. Production proceeds once the water pressure is drawn down and free gas is generated. Permeable and porous sandstones lying above or below the coal seams may contain free gas, some of which might be released during drilling. If there is free gas within the reservoir this may not necessarily lead to fugitive releases; for example, if the well is drilled ‘overbalanced’ (a common practice) such that the pressure within the well is greater than the reservoir pressure, then gas will not flow into the well. For underbalanced conditions (well pressure less than reservoir pressure) gas may accumulate within wellbores and then be released. For this situation the volume released would be limited by the wellbore volume.

Well Completion

Well completion refers to the strategies and processes used to case and cement wells. Different completions are used for horizontal and vertical wellbores and there are various techniques used in terms of well completion. Most deep wells involve installation of a steel casing which is cemented into the geological strata through which the well passes. The cement plays a very important role in that it determines the flow integrity of the well, preventing flow up the outside of the casing. Incomplete or poor cementing can lead to flow from the reservoir to other geological strata or leaks directly to surface. This type of leak could make an important contribution to fugitive emissions but procedures are in place during well construction to verify the integrity of the cement and surface leaks are easy to detect.

2.3.2 Common Well Types

1. **Horizontal wells** – These wells are commonly drilled with a 'slant interval' from surface and then deviate to become horizontal or near horizontal to follow the dip of the reservoir. CSG horizontal wells (typically termed 'surface to in-seam wells') are drilled so that each horizontal well eventually intersects a vertical well, into which a water production pump is installed and from which gas production occurs. Horizontal wells are cased to the seam of interest and usually have slotted liners installed within the horizontal section of the well. Vertical production wells can be at either the 'heel' (that is, where the slant section deviates to horizontal), or 'toe' (the end of the horizontal) of the well. The slant section may be plugged with cement or could have a cased interval to surface. From the point of view of fugitive emissions each well to surface (slant and vertical production wells) could provide an opportunity for fugitive gas release. Hydraulic fracture stimulation is commonly used in horizontal wells for shale gas production in the U.S. but currently is not commonly employed in those for CSG production, although this may increase in the future.
2. **Vertical wells** – This is a common type of well and a range of possible completion and stimulation strategies exist. Some common approaches are:
   a. **Under reaming** – a common strategy for the Walloon coal seams of the Surat Basin. These wells are cased to coal sequences. The portions of wells penetrating coal seams are reamed out to larger diameters and these under-reamed sections left uncased. An enlarged wellbore removes any drilling induced damage and provides more flow area.
   b. **Fracture stimulation** – This is a method for increasing gas and water production rates and is useful in seams having low permeability. While this technique involves a flow-back stage after stimulation driven by the residual pressure from the fracture stimulation, no drawdown in reservoir pressure occurs and is not expected to lead to release of significant amounts of reservoir gas. The exception to this would be where there has been previous production or reservoir pressure drawdown that has led to free gas within the reservoir. For this situation gas would be released during the flow-back stage although the amount of free gas present in coal is generally less than in gas shales.
3. **Monitoring wells** – Wells may also be used for various monitoring purposes, in particular monitoring CSG impacts on adjacent aquifers and to provide access for placing microseismic geophone strings for monitoring of fracture treatments. These wells could involve various completion strategies and may have cemented casing strings.

2.3.3 Production Process

As noted above, an important aspect to CSG reservoirs is that the gas is stored via adsorption as opposed to being stored within the pore space of the reservoir, as in conventional gas occurrences. This means that typically coal seams are initially water saturated with little or no free gas present. In order to initiate and eventually sustain gas production the pressure must be lowered to the desorption pressure through removal of seam water. Production may have the following stages:

1. A phase of water production where the reservoir pressure is drawn-down until gas desorption commences.
2. A typical production profile involves initially high water production which decreases with time as gas production increases.
3. A peak in gas production followed by gradual decline.

Production wells are typically completed with a tubing string run inside of the cased well. A downhole pump located at seam level is attached to the end of the tubing, through which water is pumped while gas flows in the annulus between the tubing and casing. A well head at the surface seals the annulus and tubing allowing water and gas to be produced.

3 Potential Sources of Fugitive Emissions

Methane leakages from natural gas systems depend on the type of process as well as the nature and condition of equipment employed. According to the USEPA (USEPA, 2012), natural gas exploitation can be broadly grouped into four stages: field production, processing, transmission and storage, and distribution. Each stage has its own routes of potential methane emissions, some of which are described below.

Field production: This stage includes extracting gas from wells. Methane emissions may originate from the wells themselves and from associated surface pipe work and equipment. As mentioned above, there is also the possibility of methane escaping during the preproduction stages of exploration drilling and well construction. A CSG well installation usually comprises the well, water pump, gas separator and associated valves and pipe work.

During 2010, the Queensland Department of Employment, Economic Development and Innovation (DEEDI) initiated an audit of the CSG industry in Queensland where 2719 CSG wells were inspected for leakage (DEEDI 2011a). Of these, five were found to have methane concentrations in the immediate vicinity higher than the lower explosive limit (LEL i.e. > 5 %) and a further 29 had methane levels between 10 % and 100 % of the LEL. These wells were subsequently repaired. It was also reported that numerous much lower level leaks were detected (i.e. below 10 % LEL with most below 1 % LEL), although the number was not stated. Leaks that required repair were mainly from valves, flanges and other connections but there were also several instances where gas was leaking from around the well casing. The report noted that the methodology used by the companies performing the inspections was inconsistent so that it was not possible to compare some datasets. This led to the development of a code of practice to ensure consistent inspection and reporting across the Queensland industry (DEEDI 2011b).

It is important to recognise that the method proposed in the code of practice and data currently collected do not on their own enable fugitive emissions to be quantified. Nevertheless, correct installation followed by regular inspection, including leak detection, and maintenance of equipment is essential in minimising fugitive emissions.

Processing: During processing, gas is conditioned for sale. In conventional gas production, significant quantities of hydrocarbons apart from methane may need to be removed, although for Australian CSG this is generally not the case. Methane emissions can occur from many items of equipment such as seals in compressors and the valves, flanges and associated pipe work. Deliberate venting and flaring, and equipment malfunctions or failures also contribute to fugitive emissions. Some pneumatic equipment used in the gas industry is operated with compressed gas rather than air so this too is a source of emissions.

Transmission and Storage: Once processed, gas is transported via high pressure pipelines to distribution networks or large volume customers such as LNG plants or power generators. Depending on the distance, booster compression stations may be located at points along the pipeline to maintain pressure, and these represent a route for methane leakage. Since the main CSG production sites in Australia (e.g. the Surat and Bowen Basins in Queensland) are generally remote locations a large transmission network is necessary to deliver the gas into markets.

Leakage from storage is also included in this stage. Natural gas is sometimes stored in geological strata which have the potential to leak.

Distribution: Distribution is generally considered to be the low pressure network after the transmission main and includes the retail network of pipelines that deliver gas to end users. Although significant leakage is possible in this stage (see for example Carras et al., 1991; Phillips et al., 2013) replacement of old pipe work with modern plastic pipe tends to reduce leakage in the distribution network (USEPA, 2012).

Leakage from equipment or processes is not only dependent upon the nature of the system and its general condition but also on how it is operated. Routine operation of a piece of plant may result in a different emission profile compared to when it is undergoing maintenance. Unintended events or accidents would also be expected to contribute to emissions.

4 Fugitive Emissions Estimates

The reliability of greenhouse gas emission estimates are often rated according to a three tiered system used by the Intergovernmental Panel on Climate Change (IPCC). Under this scheme, an increase in 'Tier' number corresponds to more specific and potentially more accurate estimates. Tier 1 methods are the broadest and require the least detailed information. Higher Tiers require progressively more detailed data, with Tier 3 generally considered to be direct measurement.

Tier 1 and 2 methods generally estimate emissions by multiplying the activity data (e.g. number of wells, distance of pipeline, etc.) by an emission factor. The emission factor in Tier 1 methods may be a global estimate for the process. In Tier 2, the emission factor is more specific and may relate to a particular process or piece of equipment. Although increasing Tier potentially improves the quality of emission estimates, the accuracy achieved depends very much on the quality of the both the activity data and the emission factors or in the case of Tier 3 methods, the accuracy of the measurement procedures.

Fugitive emissions by their very nature are often difficult to measure directly although some sources such as venting can be readily determined by Tier 3 methods. Most other sources, however, are estimated by lower accuracy Tier 1 and 2 methods. In many cases, the emission factors used for estimating fugitive emissions are based on limited or old data and hence may have very high associated uncertainties. This must be borne in mind when considering estimates of fugitive emissions from any source.

4.1 International Estimates

Estimates of methane leakage from the gas industry have been made since at least the early 1970s (Kirchgessner, 1997). Early estimates of global loss rates ranged from about 7 to 70 Tg CH_4 y^{-1} (147 to 1470 Mt CO_2-e, using a global warming factor of 21, as used in Australian and other national greenhouse accounting calculations). These leakage rates correspond to less than 1 % to 10 % of total gas production. However, these estimates tended to rely on data derived from unaccounted-for-gas, which is the difference between the amounts of gas sold through the distribution network and that supplied to customers. While some of this gas is in fact lost due to leakage there are numerous other unrelated factors that severely limit its use as method for estimating fugitive emissions (Haydell, 2001). These include but are not limited to:

- Measurement – i.e. uncertainty in the metering equipment at the supply and delivery ends of the network
- Differences in pressure and temperature throughout the system
- Gas theft
- Gas used to power pumps and compressors at the wells and along the pipeline
- Accounting errors such as incorrect data entry, differences in billing cycles

In Australia, unaccounted-for-gas reported by the Australian Energy Regulator since 2009 has varied between about -0.9 and +1.4 % (AER, 2012); however, in other parts of the world much higher levels have been estimated. In New Zealand for instance, it has been suggested that the average unaccounted-for-gas was about $\pm$ 2.5 %, of which less than 0.2 % is attributable to actual losses of gas, although it is not clear how this leakage rate was established (Wabnitz, 2007).

The most comprehensive study yet into fugitive emissions from the gas industry was performed during the 1990s by the USEPA (Kirchgessner, et al., 1997). This investigation examined leakages and intentional releases of methane from all points in the production chain from wells to meters at customers' premises. Detailed measurements were made of leaks from individual items of equipment at processing facilities, pumping and regulation stations, pipelines, and meters throughout the U.S. This study grouped emissions into three categories: fugitive emissions, vented gas and combustion. The fugitive emissions component is essentially leakage whereas the vented gas represents deliberate releases, and combustion is largely flaring but also included utilisation in engines, for example. In the Australian inventory, all three categories are considered to be fugitive releases except where gas is utilised in engines, in which case it is counted as energy usage.

The results from the USEPA study are summarised in Table 4.1.

Table 4.1 Summary of the methane emissions from the U.S. gas industry (from Kirchgessner et al., 1997)

Segment	Proportion of Emissions (%)	Proportion of U.S. 1992 Total Gas Production (%)
Production	26.8 ± 11.8	0.38 ± 0.17
Processing	11.6 ± 6.6	0.16 ± 0.09
Transport and storage	37.1 ± 18.5	0.53 ± 0.26
Distribution	24.5 ± 17.1	0.35 ± 0.24
Total	**100.0 ± 33.4**	**1.42 ± 0.47**

The results presented by Kirchgessner et al. (1997) show that most of the fugitive emissions from the conventional gas industry are associated with the processing, transport, storage and distribution steps with only about a quarter derived from the production phase.

The data gathered by Kirchgessner et al. (1997) were compared to the total U.S. gas production for the year of 1992 and it was found that fugitive emissions (including vented and flared gas emissions) accounted for about 1.4 % of the total production, although the uncertainty of the estimate was considered to be more than 30 %.

The Kirchgessner et al. (1997) study was conducted nearly 20 years ago but since then there have been major changes in the industry. Not only has the scale of the industry increased during this time but there have been major developments of unconventional gas reserves. The U.S., Australia and other parts of the world now have large unconventional gas industries with production approaching or even exceeding conventional gas production. In addition, there have been significant efforts to reduce methane releases through improved equipment and practices (e.g. USEPA Gas STAR Programme; see Section 6). Consequently it is probable that the fugitive emissions from at least some parts of the production chain have changed since the original study.

The USEPA recently reviewed its emissions factors for estimating fugitive emissions from gas production and, despite the apparent success of the Gas Star Programme, methane emissions from gas production were revised upwards. Fugitive methane released from the gas industry during 2008 was estimated to be 4591 Gg in the 2010 U.S. national inventory (USEPA, 2010) but in the most recent inventory, the estimate was more than doubled to 10259 Gg (USEPA, 2012). Some of this increase was attributed to methane lost during hydraulic fracturing associated with shale extraction, which now accounts for much of U.S. domestic gas production. Based on U.S. gas production data (EIA, 2009) fugitive emissions from natural gas production is equivalent to about 2.2 % of total production.

Using these revised estimates, Fulton et al. (2011) performed life-cycle-analyses for various scenarios where gas was substituted for coal for power generation. They assumed 31 % generation efficiency for coal-fired plants and 41 % efficiency for gas-fired plants. While their results showed that gas was still much less carbon-intensive than coal, the newly revised higher emissions of methane during production led to emissions about 11 % higher than based on the earlier USEPA fugitive emission estimates. However, even using the higher estimate for fugitive emissions, total greenhouse emissions per MW h of electricity were determined to be 47 % less than for coal.

The issue of potentially high fugitive emissions associated with widespread use of gas-fired electricity generation prompted Wigley (2011) to examine the climatic effects of elevated atmospheric methane levels. Wigley (2011) simulated the progressive replacement of coal during the period up to 2050 with natural gas for electricity generation. This analysis considered not only direct CO_2 emissions from combustion but also the effect of fugitive emissions from increasing gas production, the corresponding reduction in fugitive emissions from decreased coal production and finally, the reduction in aerosols from coal production and their associated cooling effect. The model was run using gas-related fugitive emissions from zero to ten percent of gas production. He found that if fugitive emissions exceed about 2 % of gas production, slight additional warming may occur.

In another recent study, an attempt was made to estimate fugitive emissions from the shale gas industry (as distinct from CSG), and to consider the climate implications of widespread utilisation of shale gas (Howarth et al., 2011). The authors compiled data from various sources such as the USEPA and industry for several shale gas fields in the U.S. The data were used to estimate emissions from the production chain: well completion, venting and equipment leaks, processing losses, and transport and distribution losses. They concluded that emissions from shale gas well completions were much higher than for conventional gas production; they suggested that an equivalent of 1.9 % of total gas production was released during the water flow-back and 'drill-out' stages compared to their estimate of 0.01 % for conventional wells. Losses from other components of the production chain were considered to be the same for both conventional and unconventional gas since much of the infrastructure is common to both. The higher emissions from shale gas wells were mainly attributed to methane entrained in the water which flows back from the well during the first few days to weeks after the wells are hydraulically fractured.

Because of the higher contribution of the wellhead emissions, Howarth et al. (2011) estimated total fugitive emissions from the shale gas industry to be between 3.6 and 7.9 % of total production over the life of the wells (cf.1.7 to 6.0 % estimated by these authors for conventional gas). Using these estimates, they compared the greenhouse footprints of shale and conventional gas with that of coal utilisation. They concluded that based on the high level of fugitive emissions, shale gas has a greenhouse intensity at least 30 % higher and perhaps more than twice that of conventional gas. Furthermore it was suggested that greenhouse gas emissions from shale gas are between 20 % and a factor of two more than for coal when the high level of fugitives and a 20-year global warming potential for methane are included in the analysis.

The conclusions presented by Howarth et al. (2011) are substantially different from all previous investigations into the relative greenhouse impacts of gas and coal so, not surprisingly, this study has generated significant discussion. In particular, Cathles et al. (2012) challenged some of the assumptions used by Howarth et al. (2011) in their analysis.

1. Cathles et al. (2012) disputed the upper estimate of 7.9 % of production proposed by Howarth et al. (2011) pointing out that it is much higher than any other previous estimate. They argue that there are no convincing data presented by Howarth et al. (2011) to support the claim.
2. Cathles et al. (2012) noted that the Howarth et al. (2011) analysis does not consider new technologies and practices that have been adopted by the gas industry in the U.S. to reduce emissions. In a subsequent paper, Cathles (2012) made the point that these technologies may be very effective, citing data from a detailed study (Harrison, 2012) of methane leakage during completions of shale gas and tight gas wells in the U.S. Harrison (2012) found that in a survey of more than1500 wells completed during 2011, 93 % were 'green completed' with average leakage rates equivalent to about 0.01 % of total gas production. This is much lower than the figure of 1.9 % estimated for well completion by Howarth et al. (2011).
3. Howarth et al. (2011) used a 20 year time horizon to compare emissions whereas most other life-cycle analyses use a 100 year period. (It should be noted that Howarth et al. also considered a 100 year horizon for comparison.) The global warming potential (GWP) of methane is significantly higher for 20 years than for 100 years but Howarth et al. argue that the shorter timeframe is relevant to the period over which mitigation is required. Howarth et al. (2011) also used a GWP of 105 for 20 years (and 33 for 100 years) rather than the previous value of 25 (100 year) proposed by the IPCC to take into account the indirect effect of methane emissions on climate (Schindell et al.,

2009). Hence the greenhouse intensities calculated by Howarth et al. (2011) are high compared to most other studies.

4. The Howarth et al. (2011) analysis compared only the energy value of coal and gas whereas Cathles et al. (2012) argued that this is not a reasonable basis for comparison since coal is widely used to generate electricity. If gas were to replace coal as the fuel for electricity generation, higher efficiency technologies would be used thus reducing the direct emissions from gas compared to coal.

Cathles et al. (2012) recalculated the data presented by Howarth et al. (2012) using what they considered to be more realistic assumptions (i.e. 60 % efficiency for gas-fired electricity generation compared to 30 % for coal, and 2.2 % fugitive emissions release from gas). The results showed that based on these assumptions, and over a 100-year GWP time frame, electricity produced from gas yielded about half the greenhouse emissions of even the most efficient coal-fired electricity generation (Figure 4.1). Cathles et al. (2012) also noted that the Howarth et al. (2011) estimate based on 7.9 % fugitives and a 20-year GWP is actually similar to greenhouse gas emissions from current coal-fired generation systems (Figure 4.1). The first column of Figure 4.1 represents emissions from coal-fired generation at 30 % efficiency, fugitive emissions of 8.4 m^3 per ton of coal from a deep coal mine, and 20-year GWP of 105. The fifth column represents emissions from gas at 60 % efficiency with the Howarth estimate of 7.9 % fugitive emissions.

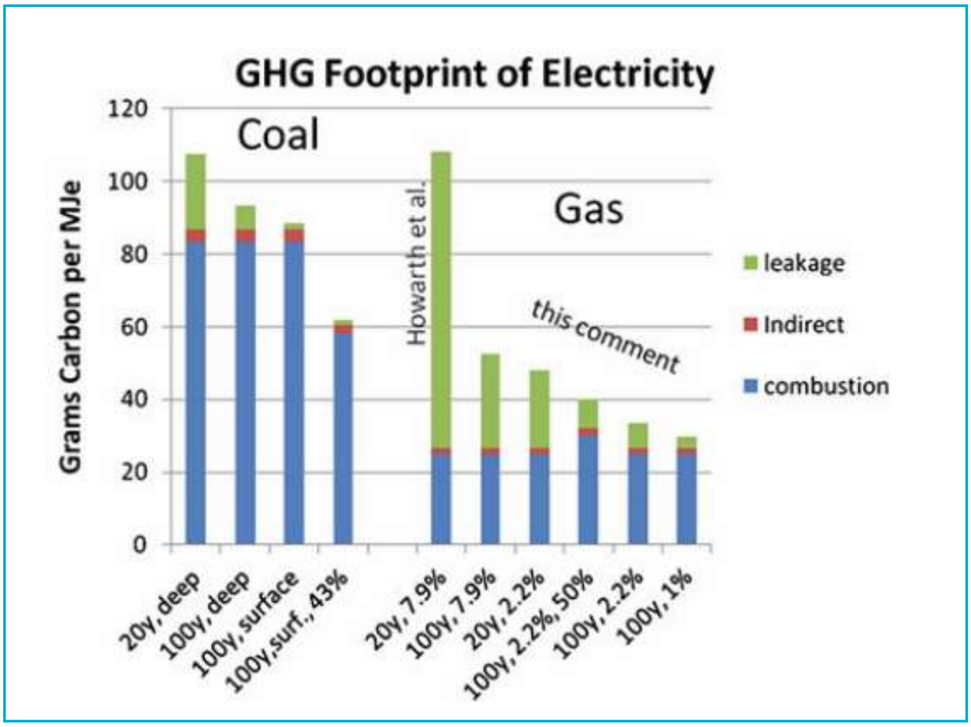

Figure 4.1 Carbon emissions calculated for coal and gas under various scenarios (from Cathles et al., 2012)

Despite the criticism, Howarth et al. rejected most of the arguments of Cathles et al. (Howarth et al., 2012). One of the bases of their rebuttal is that a number of other studies have indicated high levels of fugitive emissions from unconventional gas production. However, the results they cited highlight the central problem with making life-cycle comparisons; that is: almost all of the data upon which these comparisons are made are based on *estimates* of fugitive emissions rather than *measurements*. This point was also alluded to by Wigley (2011) who conceded that his results of climate modelling were critically dependent on the assumed gas leakage rate. This applies equally to life-cycle analyses. However, as has been noted throughout this report, fugitive emissions estimates are highly uncertain. Even the estimates for conventional gas, which is a mature technology compared to those for unconventional gas, are subject to considerable uncertainty. The IPCC estimates that in some cases, current methodology has associated uncertainties that can overestimate emissions from some parts of the gas industry by as much as 1000 % (IPCC, 2006).

A recent paper by Pétron et al. (2012) is therefore particularly relevant because it provides measurement data from which fugitive emissions from unconventional gas were inferred. This group measured atmospheric concentrations of a range of hydrocarbons, including methane, from a major gas producing region in Colorado in the U.S. The region has more than 20,000 wells producing natural gas and condensate, with about 90 % of gas production from tight gas formations.

This group found strongly correlated atmospheric methane and other hydrocarbon concentrations that they attributed to venting and leaking of natural gas, and flashing from condensate storage tanks. The data were used to calculate methane emissions by top-down and bottom-up methods (see Section 5 for descriptions of these methods). Using the bottom-up approach, methane emissions were estimated to be within the range of 46 to 86 Gg y^{-1}, with a mean of 64.3 Gg y^{-1}. The mean value is equivalent to 1.68 % of gas production from the region.

The top-down estimates were significantly higher. In this case, the estimates ranged from 71.6 to 251.9 Gg y^{-1}, with a mean of 129.6 Gg y^{-1}. This corresponds to 2.33 to 7.7 % of total production. These results are consistent with the conclusions of Howarth et al. (2011) although they are subject to large uncertainties. Pétron et al. (2012) estimated that the uncertainty of the top-down approach was around a factor of two. However, Cathles (2012) noted that condensate released from storage tanks is rich in propane relative to methane whereas the gas venting from wells contains a much lower proportion of propane. He suggested that using observed atmospheric ratios of propane to methane and the leakage rates from condensate storage vessels to calculate methane leakage from wells may significantly overestimate the methane flux.

Regardless of whether or not the results reported by Pétron et al. (2012) are an accurate reflection of methane emissions in the Colorado gas field, they are unlikely to be representative of Australian CSG operations. The Colorado field is predominantly from tight gas formations and the production methods are substantially different to those employed to extract CSG; in particular more hydraulic fracturing would have been used for tight gas production. Moreover, the extracted gas contains condensate that must be separated from the natural gas. This requires further processing which is known to result in significant fugitive losses of both the condensate and methane. This production step is not currently employed in Australian CSG operations.

4.2 Australian Estimates

During the early 1990s, Carras et al. (1991) made airborne measurements of urban methane plumes emanating from Brisbane and Sydney. For Brisbane most of the methane emissions could be attributed to landfill, however in Sydney, much higher fluxes were found. In the absence of any other sources, it was estimated that gas leakages between 10 and 30 % of the Sydney gas supply would be necessary to account for the observed methane plumes. One explanation for the high levels of methane (assuming it originated from the gas supply) is that at the time of the study, most of the network comprised old galvanised steel pipe work with sisal seals. Moisture in the manufactured coal gas that originally flowed through the pipes kept the sealant damp to maintain the seal. However with the introduction of natural gas the sealing tended to dry out and was prone to leak. Since that study was conducted, the gas reticulation system has been largely replaced and it is probable that any leakage has been significantly reduced. This tends to be supported by the relatively low levels of unaccounted-for-gas levels of less than about 1.5 % that have been reported in more recent years (AER, 2012). Very recent research in the U.S. also confirms that gas leakage is mainly associated with older metal pipe networks (Phillips et al., 2013).

The Carras et al. (1991) study remains the only investigation of fugitive emissions from gas reticulation in Australia. However, with the introduction of the National Greenhouse and Energy Reporting Act (2007), Australian oil and gas (and coal) producers are now required to estimate and report their fugitive emissions each year. These data are used for calculating liabilities under the carbon pricing legislation and also for compiling the National Greenhouse Gas Inventory. During 2010, fugitive emissions reported for gas production (including CSG) were about 12 Mt CO_2-e (DCCEE, 2012a). Assuming that all of the fugitive emissions are released as methane, Australian emissions correspond to 0.57 Mt of methane, which represents 1.5 % of the gas produced during that period (1997 PJ or 37 Mt CH_4; BREE, 2012). In fact, this is an overestimation because some fugitive methane is flared to produce CO_2 rather than being directly released as methane. The estimate is, however, in close agreement with the estimate of fugitive emissions from the U.S. gas industry reported by Kirchgessner et al. (1997) but somewhat less than the current U.S. estimate of about 2.2 %.

The fugitive emissions data reported to National Greenhouse and Energy Reporting System (NGERS) are subject to significant uncertainties and do not provide information specific to the CSG industry. The bulk of the reported fugitive emissions are due to venting and flaring which can be estimated to reasonable confidence – in some cases with Tier 3 methods. However, for CSG production, most of the emissions from this sector are estimated using Tier 1 and 2 methods described in the American Petroleum Institute's (API) Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry, with emissions factors based on U.S. operations (API, 2009).

During 2011, a study commissioned by the Australian Petroleum and Production and Exploration Association (APPEA) was undertaken to assess the relative greenhouse emissions from electricity production fuelled with coal and with CSG-derived LNG (i.e. Clark et al., 2011). Like other life-cycle-analyses, the results showed that when compared to subcritical coal combustion (33 % efficiency), CSG utilisation in combined-cycle generation (53 % efficiency) yielded about half the greenhouse gas emissions. However, fugitive emissions were assumed to be only 0.1 % of gas production which is much lower than estimates from other gas production sectors. The authors noted that the value of 0.1 % represents industry accepted practice (see Table A4.4 in Clark et al., 2011), although it is not clear how this level was established. A similar estimate was made in the environmental impact statement for the Gladstone LNG project proposed for Queensland (GLNG, 2009).

Since the publication of the Clark et al (2011) study, the authors have re-examined their conclusions in light of the results which have been subsequently reported in the U.S. (see Hardisty et al., 2012). Using similar methodology to their original study, Hardisty et al. (2012) recalculated greenhouse emissions for a range of energy scenarios. Their base case assumed fugitive emissions of 2.8 Mt CO_2-e for a 10 Mt pa LNG plant which is equivalent to 1.3 % of production. They also considered a higher value (4.38 % of production, i.e. the average of the top down estimates made by Pétron et al., 2012) and a 20-year GWP as proposed by Howarth et al. (2011). While CSG was still found to be more favourable than coal for electricity generation, the greenhouse advantage was much less than previously reported. In the worst case scenario considered (i.e. fugitive emissions 4.38 % of production, 20-year methane GWP), electricity produced from CSG-derived LNG has almost the same greenhouse intensity as subcritical coal-fired generation (but less than the estimate made by Howarth et al., 2011 for shale gas).

Although there have been no direct measurements of fugitive emissions from Australian CSG facilities, safety concerns have prompted more rigorous monitoring of well heads to detect and repair methane leaks (DEEDI, 2011a). The results of this monitoring suggested that leakage rates from surface facilities of the CSG wells examined were relatively low and did not pose a significant safety risk. However, it was also noted that there were numerous low level leaks detected. If unchecked these leaks would be a source of fugitive emissions.

Emissions during the exploration and well completion stages were not examined during the DEEDI study and notwithstanding the differences between shale gas and CSG production it is noteworthy that a large proportion of the fugitive releases estimated by Howarth et al. (2011) were attributed to pre-production. Hence methane emission from pre-production processes in CSG is an area requiring further investigation.

In summary, it is clear that a comprehensive data set relating to the true scale of fugitive emissions from the CSG industry does not yet exist. Estimates for unconventional gas in general range from 0.1 to almost 8 % of total production (Table 4.2). Only two of the estimates (Kirchgessner et al., 1997 and Pétron et al., 2012) are based on measurements of emissions.

Table 4.2 Summary of estimates of fugitive emissions from gas production (expressed as a percentage of total production)

Study	Emissions Estimate (% of total production)	Notes
Kirchgessner et al., 1997	1.42	Emissions measurements were made for the U.S. conventional natural gas industry.
Howarth et al., 2011	3.6 to 7.9	Related to the shale gas industry in the US. Conclusions were based on estimates and assumptions rather than direct measurements.
USEPA	2.2	This value was calculated from U.S. gas production data (also used by Cathles et al., 2012).
Pétron et al., 2012	1.68 to 7.7	Estimates were calculated from atmospheric measurements of methane and other hydrocarbons in a (tight-gas dominant) gas field in Colorado.
Clark et al., 2011	0.1	Estimate used for comparing CSG with other fuels. Figure based on industry 'accepted practice'.
Hardisty et al., 2012	1.3 to 4.38	Recalculated life-cycle analysis for CSG from Clark et al., (2011) using revised fugitive emissions estimates reported since their first study.

Most of the estimates reported relate to the gas industry in the Unites States where the geology, production methods and scale of operations are substantially different from those related to the CSG industry in Australia. Hence it is unlikely that the U.S. data are a suitable guide to the situation in Australia, and in any case, the estimates that have been reported are very uncertain. As well as the uncertainty on the levels of emissions themselves, the extent of their effect on climate change is also open to question, especially as to whether the global warming potential should be considered over a 20-year rather than the more commonly used 100-year period and whether the indirect effects of methane on climate should be included (Schindell et al., 2009). Both considerations would lead to larger methane GWPs. There are also questions about the suitability of GWP as a metric for greenhouse gas mitigation strategies (Manning and Reisinger, 2011).

5 Methods for Measuring Fugitive Emissions

Under the NGERS legislation, fugitive emissions from the Australian gas industry must be estimated according to methods consistent with National Greenhouse and Energy Reporting (Measurement) Determination 2008 (DCCEE, 2012b). The Determination provides a basis for estimating emissions according to four generic 'Methods'. Within each Method are specific procedures that detail how emissions are to be estimated and reported. In many cases, the Methods specify international standards or industry methods that must be used for estimating emissions. The four Methods are described below.

- Method 1 is the simplest approach and relies on activity data and an emission factor for the process. The emission factors used in Method 1 are generic and are usually specified in the NGER Determination.
- Method 2 is more specific and uses emission factors based on more detailed data.
- Method 3 is very similar to Method 2 except that the methods are based on internationally accepted standards.
- Method 4 is the direct measurement of emissions.

In the natural gas industry, emissions due to venting may be measured using Method 4 (i.e. direct monitoring). In these instances, robust emissions estimates should be possible with commercial process instrumentation. Most other sources of emissions are, however, not readily amenable to Method 4 and hence other simpler methods are used. For flared gas, emissions may be calculated by either Methods 1, 2 or 3. Provided the quantity of gas going to the flare is accurately measured, emissions calculated by even Method 1 would be reasonably accurate.

Emissions from leakage sources, which include leaks from equipment and pipelines during exploration, production, processing, transmission and distribution are estimated by either Method 1 or 2. Method 1 uses emission factors specified in the Determination for several types of storages tanks and a general emission factor intended to account for leaks during production and processing. The factor used to account for leaks is 1.2×10^{-3} t methane per tonne of gas produced, or 0.12 % of production (Saddler, 2012).

Method 1 (for venting) and Method 2 (for leakage) are based on the procedures detailed in the API 2009 Compendium (API, 2009). In general, these provide engineering calculation approaches or emission factors for process operations, individual items of plant and length of distribution pipe networks. There can be, however, considerable uncertainty associated with the emission factors. For instance, the stated uncertainty for the emission factors recommended for gas dehydration systems is in some cases more than 250 % (Table 5.2 API Compendium). In another example for maintenance activities the uncertainty is almost 1000 % (Table 5.23 API Compendium). When combined with the uncertainty associated with the activity data, very high overall uncertainties result. Moreover, actual emissions are likely to depend strongly on the type and condition of equipment installed at a facility as well as how it is operated (see Section 3).

Coal seam gas operators, like other gas producers, are required to report fugitive emissions under NGERS using methods provided in the Determination. The API 2009 Compendium, referred to in the Determination, discusses coal bed methane (i.e. CSG) and provides methods for estimating fugitive emissions from various points along the production chain, but again these are usually based on old U.S. data that may not be applicable to current Australian operations.

Given the uncertainties inherent in the current methodologies used for estimating fugitive emissions from many sectors of the gas industry generally, and the lack of specific information regarding emissions from the Australian CSG industry in particular, the following sections consider possible approaches to measuring emissions (i.e. Tier 3 methods) from all sections of the CSG production chain, including wells.

When developing methods for measuring fugitive emissions, there are two general approaches: 'bottom-up' and 'top-down'. Bottom-up methods are more specific, requiring information from individual sources, which are then aggregated to yield a total emission for the facility or industry. This is the general principle of the methods currently used in the NGER Determination for estimating fugitive emissions from the gas industry.

The alternative is to use a top-down approach where emissions are measured over a much broader scale.

5.1 Bottom-Up Methods

Bottom-up methods include those where emission rates from parts of the process are examined individually. One advantage of this approach is that provided suitable techniques are available or can be developed, leakage rates from specific items of equipment or processes can be measured directly. The major disadvantage is that a large number of individual measurements may be necessary to adequately characterise the process or industry. This was illustrated during the USEPA study of emissions from the U.S. natural gas industry where more than 200,000 measurements were made at 33 sites across the U.S. (Kirchgessner et al., 1997). Fully characterising the CSG industry in Australia using the bottom-up approach would also require a very large measurement programme. Despite the problems of representative sampling, bottom-up methods are important because they yield information on the leakage characteristics of equipment, which is essential in developing effective mitigation strategies.

The general methodology used by Kirchgessner et al. (1997) in the USEPA study would be similar to that required for measuring emissions from the Australian CSG industry. In one part of the USEPA study, equipment was screened for leaks using USEPA Method 21 (Determination of volatile organic compound leaks). This method uses a handheld instrument to detect leaks in process equipment by measuring concentrations of volatile organic compounds (VOCs) in ambient air near the equipment, and is similar to the procedure recently proposed in the Queensland Government's Code of Practice (DEEDI 2011b). The emission rate of methane leaking from the equipment was then measured by enclosing the system in a flexible enclosure (bagging) to trap leaked gas. By passing a carrier gas through the bag, the emission rate, F, was determined by measuring the total flow of gas from the bag, f_b, and the concentration of methane in the gas stream, C, according to Equation 5.1.

Eq 5.1

As this is a slow procedure the USEPA study also used alternative methods to measure emissions rates. In the first, a system known as the GRI Hi-Flow generated a gas flow field around the component that entrained any leaking methane, which was then directed into the instrument to measure the methane concentration and flow rate. The GRI Hi-Flow system, which was developed for the project, is a portable instrument that could be carried by a single operator around test sites.

The second approach relied on correlations between previously established emission fluxes and gas concentrations for particular items of equipment. This allowed simple leak testing data to be used to estimate emission rates. This method is subject to higher uncertainty than the other measurement methods; however, it allows a much greater rate of sampling to be achieved. An example of the correlation for pipe connectors determined during the USEPA study is shown in Figure 5.1. Note that the scales of both axes of this plot are logarithmic, which illustrates the very high uncertainty of this approach.

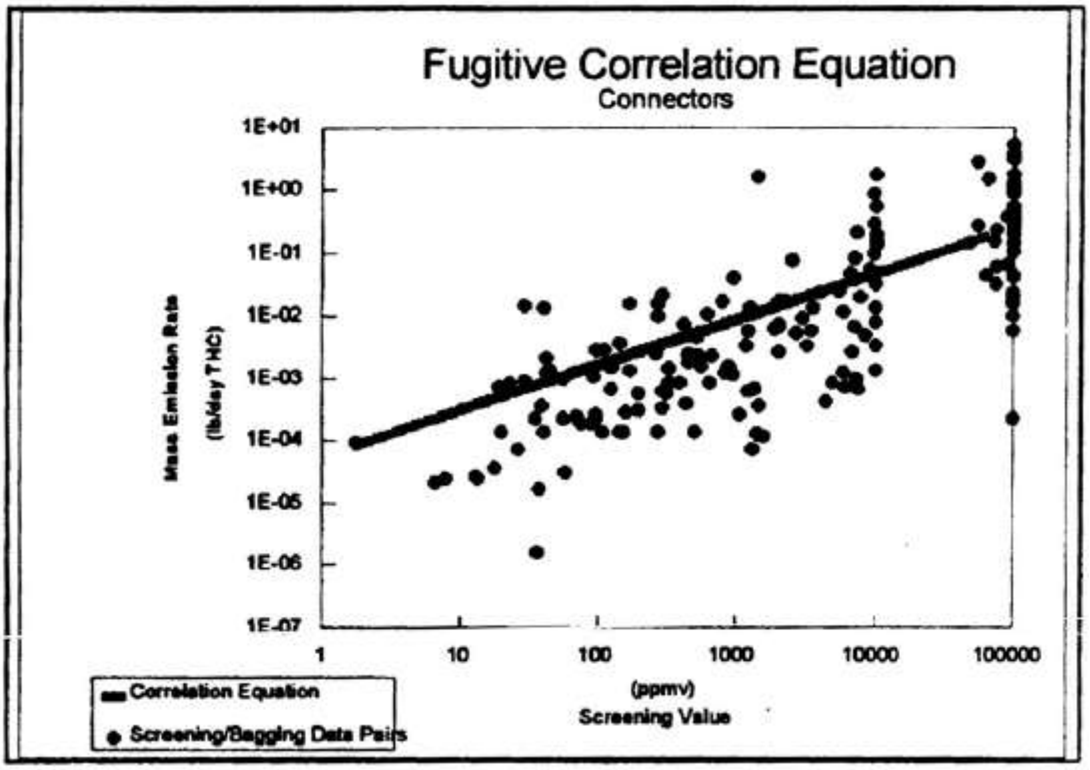

Figure 5.1 An example of the correlation between emission flux (ordinate) and near field methane concentration (abscissa) for processing equipment (from USEPA, 1996). Note that both axes have logarithmic scales.

Similar relationships were established for many other components and the resulting regression equations provide the basis for equipment-specific emission factors used throughout the industry for estimating fugitive emissions.

Both the enclosure and correlation methods are routinely used in the petroleum industry to detect and measure leaks from plant in refineries and detailed procedures are provided in the USEPA Protocol for Equipment Leak Emission Rates (USEPA, 1995). This protocol provides correlations for VOCs specific to the oil industry, so part of the USEPA natural gas study was devoted to developing correlations suitable for equipment in the gas industry.

It is possible that similar correlations could be developed for the CSG industry in Australia. This would be useful in that much of the leak detection data already gathered by the industry may be used to infer emission rates. It would however, require a detailed study to establish and validate such correlations.

As well as being useful for measuring leakage rates from equipment, enclosure methods are easily adaptable to investigate emissions from other sources. For example, they can be used for measuring emissions from the ground surface near wells, or even from wells themselves. This method has been used previously to measure greenhouse gas emissions from spontaneous combustion in spoil piles at open-cut coal mines (Carras et al., 2009). In that application, rather than using flexible bags to enclose items of equipment, rigid polycarbonate chambers were placed on the ground to measure emissions from below the surface. This method would be important to help establish natural background levels of methane emissions in areas gas extraction has not occurred. In these cases where the emission fluxes are likely to be low, the chambers would be used without a carrier gas to improve sensitivity. The rate of increase in concentration, R_c, is monitored instead and the emission flux per unit area determined according to Equation 5.2.

Eq 5.2

The terms V_c and A are the volume and cross-section area of the chamber, respectively.

In some instances of deliberate venting it may be more appropriate to calculate the emissions using engineering data rather than measuring them. This method was used during the USEPA study (Kirchgessner et al., 1997) for events such as 'blowdowns' (i.e. where the gas in certain pieces of equipment or pipelines is released for repairs). If the pressure of the gas and volume of the pipe is known it is straightforward to calculate the volume of gas released.

Certain atmospheric methods may also provide bottom-up estimates where measurements are made close to facilities. Plume traversing, for instance, could be used to measure emissions from individual well installations. In these cases, a vehicle fitted with a suitable methane analyser would be driven downwind of the source to measure the concentration of methane in the resultant plume. Meteorological data for the site would be used in conjunction with the concentration data to determine the emission flux from the targeted facility. This approach has been used recently to monitor hydrocarbon leaks from a natural gas field (Hirst et al., 2004) and leakage from a CO_2 sequestration site (Krevor et al., 2010). Pétron et al. (2012) also used a vehicle to traverse methane plumes during their campaign in the Colorado gas field, although they did not use plume modelling to infer emission flux.

5.2 Top-Down Atmospheric Methods

An alternative but also complementary approach to estimating emissions is by top-down methods. Whereas the bottom-up methods described above are proximal to facilities or even individual items of equipment, top-down methods can cover larger areas. This approach measures total emissions from the combined source and therefore is not subject to the problem of bottom-up methods where significant individual sources may be missed. In many cases atmospheric techniques yield continuous monitoring, which is important since fugitive emission rates and locations can change over time.

Several atmospheric methods can be applied to monitoring gas emissions to the atmosphere from point or diffuse surface sources but an essential step in the atmospheric approach is to derive emissions (i.e. fluxes) from concentrations. This usually involves measuring changes in concentrations over space and time from which fluxes are derived using enclosures, micrometeorological methods, transport modelling or tracers. Leuning et al. (2008) described these techniques and their application to potential leakage of geologically stored CO_2, which may also be relevant to fugitive methane emissions. Loh et al. (2009) applied one of these techniques, backward Lagrangian Stochastic (bLS) dispersion analysis, to releases of CO_2 and methane from a line source and found considerable success in quantifying the emissions. Methane (and other trace gas) emissions are easier to quantify than CO_2 because of lower and more stable background atmospheric variations (CO_2 being strongly affected by the ecosystem). Humphries et al. (2011) used upwind-downwind differences in concentration across a network of sensors to accurately infer the location and emission rate of a source of CO_2 and nitrous oxide (N_2O). These studies applied to source regions of tens to hundreds of metres with monitoring instruments sited immediately adjacent. Sources have been detected over larger scales and quantified by optimising concentrations simulated by transport models to the measured variations, for example, for CO_2 and methane at a geological storage site (Etheridge et al., 2011), perfluorocarbon CF_4 from aluminium smelters in south east Australia (Fraser et al., 2011) and methane emissions from south east Australia (Wang and Bentley, 2002; Loh et al., 2011).

Atmospheric methods have been used successfully in measuring fugitive emissions from the coal industry. The results of one of the earliest studies of fugitive emissions from open-cut mining form the basis of Method 1 in the NGER Determination for estimating emissions from the Australian coal industry (Williams, et al., 1993). More recently, plume traversing and inverse modelling have been employed to measure emissions from spontaneous combustion in spoil piles in mines in NSW and Queensland (Lilley et al., 2008; Lilley et al., 2012). Wide area measurements using aircraft have also been used to measure fugitive methane emissions in Brisbane and Sydney (Carras et al., 1991). Recent measurements at a monitoring station in Queensland (Berko et al., 2012) have detected methane sources that are consistent in location and emission rate with individual coal mines up to 50 km away.

Uncertainties can be significant in all the methods mentioned above and an important aspect of any measurement programme would be to define the magnitude of these uncertainties. For atmospheric methods, uncertainty derives from inaccuracies in measurement and transport modelling. Recent improvements in measurement technologies, however, have resulted in field deployable instruments for continuous and precise monitoring of a range of gases and their isotopes.

One of the principal disadvantages of wide area atmospheric methods is that emissions from sources other than that under investigation may be detected. For instance, methane from natural or agricultural sources will be superimposed on methane emissions from CSG activities. In the Carras et al. (1991) study, landfill sources were a significant contributor to the observed methane signal. This complicates the interpretation of the data and careful analysis is required to ensure that emissions from only the CSG sources are quantified. Knowledge of the area of surveillance may help to identify some of the non-CSG sources, but other methods may also be required. In the study undertaken in the Colorado gas field, for example, Pétron et al. (2012) used the elevated levels of higher hydrocarbons associated with the natural gas to effectively identify spurious methane sources. Coal seam gas generally does not have high level of hydrocarbon marker compounds so other techniques may be needed for identifying emissions from Australian CSG fields. One option could be to use measurements of the isotopic composition of methane to discriminate emissions from CSG sources from other methane sources such as landfills and agriculture. However, sophisticated analyses of the fugitive gases, generally at trace levels, will be necessary and this adds a level of complication to the procedure.

Another option for atmospheric monitoring would involve the measurement of introduced tracer gases. For this, a distinctive tracer compound would be added to the system so that the tracer would show up in any leaks from the gas facility. This was one of the methods used by Kirchgessner et al. (1997) during the USEPA study. Introduced tracers, however, can be problematic since they may be costly, are commonly potent greenhouse gases themselves or may have other environmental issues.

6 Opportunities for Mitigation

In the U.S., the USEPA operates the Natural Gas STAR programme which is designed to reduce methane release from the natural gas industry. This is a voluntary programme that has been running since 1993 where companies are encouraged to adopt technologies and practices to reduce methane emissions. Recently, the programme was expanded to allow international organisations to participate.

Under this scheme, participating companies report activities to reduce methane emissions each year. According to the Natural Gas Star website (http://www.epa.gov/gasstar/accomplishments/index.html), 994 Bcf (~28×10^9 m^3) of methane release has been avoided over the programme's lifetime in the U.S. and a further reduction of 77.8 Bcf (2.2×10^9 m^3) has been attributed to the international scheme.

Some of the main areas where emissions reductions have been made are shown in Table 6.1 (from Hardisty et al., 2012).

Table 6.1 Methane leakage sources and possible mitigation measures (from Hardisty et al., 2012).

Source	Mitigation Method
Venting from exploration wells, well completions and workovers	Capturing vented gas for sale Capturing gas entrained in water from wells Flare gas if it cannot be used Minimise periods where venting is unavoidable
Venting from compressors and pneumatic devices	Use electrically powered rather than gas powered compressor stations Flare waste gas where possible Avoid the use of gas actuated pneumatic systems
Leaks	Equipment maintained to a high standard Regular leak testing and repairs

The Australian CSG industry does not directly participate in the U.S. Gas STAR Programme; however, it seems likely that many of the mitigation practices that have been developed over the past 20 years are being adopted by the local industry. For instance, it appears that most of the pneumatic equipment used in Australia is air actuated rather than gas operated (Hardisty et al., 2012). As well, the Queensland industry now has an extensive inspection regime to minimise leakage from surface equipment.

A detailed inventory of the industry would be necessary to identify if and where mitigation is required.

7 Research and Development Required

Although fugitive emissions are an important source of greenhouse gases, global estimates are highly uncertain. Even for conventional gas production where the sources of emissions are relatively well understood, Tier 3 data on the scale of these emissions are scarce. For unconventional gas, there are very few data relating to fugitive emissions.

Recent studies in the U.S. have attempted to estimate emissions from the U.S. unconventional gas industry, but these were based on limited data and the conclusions are open to question due to the high uncertainties. In any case, the investigations were concerned with shale gas or tight gas production so it is probably not valid to extrapolate these findings to the Australian CSG industry. There are no experimental data on the extent of fugitive emissions from CSG installations and research is required to quantitatively account for emissions from domestic CSG production and distribution, including production of LNG for export.

A possible work programme to address the issues raised in this report would include firstly the development of appropriate methodologies to measure emissions from all stages of production, distribution and downstream processing. The next phase would involve longer term monitoring across the industry to develop an inventory of emissions. The key points of such a work programme are discussed in more detail in the following sections.

7.1 Methodology Development

The first phase of a research programme into fugitive emissions from the CSG industry in Australia would include method development for both top-down and bottom-up approaches. Atmospheric methods incorporating inverse modelling would be a key component of this phase. A network of fixed monitoring stations located around major CSG facilities offers the potential to provide continuous, top-down monitoring of emissions over wide areas. This approach is well suited to regions of distributed, time varying sources such as multiple wells. One of the main challenges to be addressed in this approach is how to account for sources of methane apart from emissions from CSG production. This may involve determining emission ‘signatures’ (e.g. isotopic ratios) from a variety of sources to facilitate discriminating the CSG methane signal.

Smaller scale bottom-up atmospheric monitoring would also be an essential component of a research programme. Here instrumented vehicles or possibly unmanned aerial vehicles (UAVs) would be used to track and characterise methane plumes associated with particular stages of production etc. These plume traverses would cover much smaller areas than fixed monitors but they offer advantages in that specific parts of the process can be targeted and they may avoid other sources of methane.

Measurements at the well and equipment level are also necessary to define emissions. These methods would include measuring leakage from specific items of equipment by enclosing them in specially designed chambers. This approach can be readily adapted to measure emissions from most stages of production from well heads to customers’ meters. It is also recommended that consideration be given to establishing any correlations between the measured leakage rates and the concentration data gathered during leak testing inspections. The scale of CSG operations is such that the enclosure approach to measuring emissions can at best only examine a sample of the emissions sources. However, it is possible that such methods may be developed to provide emission factors suitable for routine reporting to meet NGER obligations.

It will be essential to establish the natural background of methane concentrations and land-air fluxes in CSG regions, using a combination of chamber measurements, eddy covariance flux towers, and baseline monitoring stations. These baseline measurements should preferably begin at least a year before production to allow for natural annual variations.

The methodologies developed would enable emissions to be monitored over a range of scales, i.e. from point emissions, to small footprint fluxes and eddy covariance tower footprint, through to wide area monitoring. This would provide an integrated and consistent approach to estimating fugitive emissions and would also provide confidence in the estimates by allowing cross checking against several independent methods.

7.2 Monitoring

Once suitable methods have been developed in the first phase, longer term monitoring would be required to build an accurate inventory of emissions. It is envisaged that during this phase, automated monitoring networks would be established at appropriate sites to measure atmospheric levels of methane, which would be used in atmospheric models to measure emission flux. Continuous monitoring would allow changes in emissions over time to be quantified.

In addition to automated monitoring, a more extensive set of enclosure measurements could be made across the industry to determine the range of emissions from the various stages of production. This will be essential in developing effective mitigation strategies, if necessary. A key part of the monitoring phase would be to establish the contribution to methane emissions from natural and other non-CSG sources. The significance of leakage rates from abandoned or decommissioned wells should also be determined.

The data provided during this phase have the potential to yield improved emission factors that would ultimately lead to more accurate NGERS reporting of fugitive emissions from the CSG industry.

7.3 Leak Detection

Detecting leaks in equipment and pipelines is essential to managing operations to reduce fugitive emissions. Investigation of cost-effective systems for rapid detection of leaks from CSG infrastructure, especially in remote regions where leaks may go unnoticed for extended periods, may be required. Possible systems include aircraft mounted remote sensing and unmanned aerial vehicle (UAV) technology, both of which can cover large areas quickly. A major challenge will be to improve the sensitivity of instrumentation fitted to these platforms so that low level leaks can be identified.

7.4 Life-Cycle Analysis

As mentioned earlier in this report, life cycle analysis has been widely used in recent years to compare the greenhouse gas footprint of electricity generated from various fuel types. It is critical that a life cycle-based approach be taken in such assessments in order to provide true environmental impacts.

However, if valid comparisons are to be made, all greenhouse gas emissions over the various life cycle stages of electrical power generation must be accurately accounted for. Fugitive emissions are significant sources of such emissions and it is therefore crucial that reliable data on fugitive emissions be used in these life cycle analyses. To this end, the building of a robust inventory of whole-of-life greenhouse gas emissions from CSG production and utilisation as mentioned above would allow true comparisons of the greenhouse gas impact of CSG-based electricity with other energy sources, in particular coal and conventional natural gas.

Acknowledgements

We gratefully acknowledge the many insightful discussions and comments from numerous of our colleagues across CSIRO that have helped to improve this report. In particular we would like to thank John Carras, Patrick Hartley, Rob Jeffery, Mary Mulcahy, Peter Stone and David Williams for their help.

Abbreviations

APPEA	Australian Petroleum Production and Exploration Association
API	American Petroleum Institute
Bcf	billion cubic feet
CBM	coal bed methane
CSG	coal seam gas
DCCEE	Department of Climate Change and Energy Efficiency
DEEDI	Queensland Department of Employment, Economic Development and Innovation
Gg	gigagrams (10^9 g)
IPCC	Intergovernmental Panel on Climate Change
LNG	liquefied natural gas
Mt	megatonnes (10^6 t)
NGERS	National Greenhouse and Energy Reporting System
PJ	petajoules (10^{15} J)
Tg	teragrams (10^{12} g)
USEPA	United States Environmental Protection Agency

Lilley, W., Day, S., Williams, D., Rae, M., Carras, J., 2012. A comparison of three methods for the quantification of greenhouse gas emissions from spontaneous combustion in open-cut coal mines. Greenhouse Gas Measurement and Management. 2, 93-105.

Loh, Z., Leuning, R., Zegelin, S. J., Etheridge, D. M., Bai, M., Naylor, T., et al., 2009. Testing Lagrangian atmospheric dispersion modelling to monitor CO_2 and CH_4 leakage from Geosequestration. Atmospheric Environment 43(16), 2602-2611.

Loh, Z.M, Law, R.M., Corbin, K.D., Steele, L.P., Krummel, P.B. Fraser, P.J., Zahorowski, W., 2011. Methane simulations at Cape Grim to assess methane flux estimates for south east Australia, 5th CAWCR Annual Workshop, Melbourne, Australia, 15-17 November 2011. Centre for Australian Weather and Climate Research. 1 p. (http://www.cawcr.gov.au/publications/technicalreports/CTR_044.pdf).

Manning, M., Reisinger, A., 2011. Broader perspectives for comparing different greenhouse gases, Phil. Trans. R. Soc. A 369, 1891–1905. doi:10.1098/rsta.2010.0349.

Pétron, G., Frost, G., Miller, B. R., Hirsch, A. I., Montzka, S. A., Karion, A., Trainer, M., Sweeney, C., Andrews, A. E., Miller, L., Kofler, J., Bar-Ilan, A., Dlugokencky, E.J., Patrick, L., Moore Jr., C.T., Ryerson, T.B., Siso, C., Kolodzey, W., Lang, P.M., Conway, T., Novelli, P., Masarie, K., Hall, B., Guenther, D., Kitzis, D., Miller, J., Welsh, D., Wolfe, D., Neff, W., Tans, P., 2012. Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study. Journal of Geophysical Research-Atmospheres, 117. D04304.

Phillips, N.G., Ackley, R., Crosson, E.R., Down, A., Hutyra, L., Brondfield, M., Karr, J.D., Zhao, K., Jackson, R.B., 2013. Mapping urban pipeline leaks: methane leaks across Boston. Environmental Pollution 173, 1-4.

Saddler, H., 2012. Review of literature on international best practice for estimating greenhouse gas emissions from coal seam gas production. Report prepared for the Department of Climate Change and Energy Efficiency. Pitt & Sherry. (http://www.climatechange.gov.au/media/whats-new/~/media/government/submissions/nger/coal-seam-gas-methods-review-2012.pdf).

Shindell, D.T., Faluvegi, G., Koch, D.M., Schmidt, G.A., Unger, N., Bauer, S.E., 2009. Improved attribution of climate forcing to emissions. Science 326, 716-718.

USEPA, 1995. Protocol for Equipment Leak Emission Rates. U.S. Environmental Protection Agency, Washington DC. (http://www.epa.gov/ttnchie1/efdocs/equiplks.pdf).

USEPA, 1996. Methane emissions from the natural gas industry – Volume 8: Equipment leaks. U.S. Environmental Protection Agency, Washington DC.

USEPA, 2010. Inventory of U.S. greenhouse gas emissions and sinks: 1990-2008. U.S. Environmental Protection Agency, Washington D.C. (http://www.epa.gov/climatechange/Downloads/ghgemissions/508_Complete_GHG_1990_2008.pdf).

USEPA, 2011. DRAFT: Global anthropogenic non-CO_2 greenhouse gas emissions: 1990 – 2030. U.S. Environmental Protection Agency, Washington DC. (http://www.epa.gov/climatechange/economics/downloads/EPA_NonCO2_Projections_2011_draft.pdf).

USEPA, 2012. Inventory of U.S. greenhouse gas emissions and sinks: 1990-2010. U.S. Environmental Protection Agency, Washington D.C. (http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html).

Wabnitz, G., 2007. Allocation of unaccounted-for-gas. Maunsell Limited, Wellington. (http://gasindustry.co.nz/sites/default/files/publications/Allocation_of_Unaccounted_for_Gas_-_Maunsell_Ltd.pdf).