Review of literature on international best practice for estimating greenhouse gas emissions from coal seam gas production

Prepared for: Department of Climate Change and Energy Efficiency

Prepared by: Hugh Saddler
August 2012

transport infrastructure | community infrastructure | industrial infrastructure | climate change

pitt&sherry

sustainablethinking®

Table of contents

Authorised by: **Date:** 19 September 2012
Name Hugh Saddler

1. Background

Coal seam gas (CSG) is assuming growing importance as a source of gas for both domestic use (pipeline gas) and export (LNG) in Australia. Australia is the third country to have established significant new oil and gas sector activity based on this resource, following the USA and Canada (where it is called coal bed methane). In the USA, there is also very significant production of shale gas. For reference, production in the province of Alberta, where all Canadian production is located, was approximately 340 PJ in 2010 (calculated from data at http://www.energy.alberta.ca/NaturalGas/940.asp), while production in Queensland, where almost all Australian production is currently located, was 234 PJ in 2010–2011 (Queensland Government 2012). US production of coal bed methane and shale gas combined is very much larger.

Extraction of CSG and shale gas differs from the extraction of conventional natural gas in two important ways. First, many more wells are drilled for a given volume of gas production. Second, much more extensive use is made of hydraulic fracturing ('fracking') of the gas-bearing rock strata, to release the gas. Because of these reasons, it is thought likely that the sources, and perhaps also the volumes, of fugitive methane releases may differ from those associated with conventional gas production, and that consequently different approaches to the measurement of fugitive emissions may be required.

In this context, the term 'fugitive emissions' is used in the narrow sense in which it is used by the oil and gas industry, meaning emissions that are uncontrolled (in more colloquial terms, leaks). This is in distinction to the much broader sense in which the term fugitive energy emissions is used in greenhouse gas inventories.

The methodology for estimating emissions from uncontrolled fugitive emissions is specified in Sections 3.72 and 3.73 in Division 3.3.6, 'Natural gas production or processing (other than emissions that are vented or flared)', of the *National greenhouse and energy reporting (NGER) measurement determination 2008*. The text states that natural gas includes CSG. Two methods are provided. Method 1, which is derived from the National Greenhouse Accounts, specifies (very small) default values of throughput volume based emission factors for three different types of storage tank, plus a general throughput based emission factor with a default value of 1.2×10^{-3} t methane per tonne of natural gas, that is, approximately 0.12%, for all other uncontrolled emissions. Method 2 is based on the *Compendium of greenhouse gas emissions estimation methodologies for the oil and gas industry 2004* of the American Petroleum Institute (API). It uses separate emissions factors for a range of different types of equipment used in the production and processing of natural gas.

In addition, Section 3.84 in Division 3.3.9, 'Natural gas production or processing (emissions that are vented or flared)', specifies methodologies for emissions, mainly of methane, from what are called deliberate releases from process vents, system upsets and accidents. Emissions in this category are deliberate, in the sense that operators know when they will occur or are occurring, but are not necessarily fully controllable. Emission sources covered include, among others, exploration drilling and well testing, blowdowns, well completions and workovers. These are all classed as non-routine activities, in that they generally occur infrequently over the life of any individual well but, under some circumstances, emissions from a single event may be quite large.

The key point about all these methodologies is that they were specifically designed for use by the conventional natural gas industry, not for CSG production. This may well be appropriate for equipment used at gas processing facilities, since this is essentially the same for both gas sources. It may also be appropriate for gathering pipelines and compressors. However, it is less likely to be appropriate for wellheads and it certainly does not address the possibility of uncontrolled emissions of methane escaping through the ground around wells, as has been claimed to occur in some CSG fields. It should also be noted that the emission factor values recommended in the API *Compendium* are mostly derived from measurements made in the USA in the1990s, and so may not be appropriate for Australia today, and in the future.

pitt&sherry was commissioned to review international best practice in methods for the estimation of fugitive emissions from CSG extraction, with a view to determining whether there have been any recent developments in methods which may differ from methods used for conventional natural gas and be applicable to estimating emissions from CSG in Australia.

2. Literature overview

According to a recent report from the International Energy Association (IEA 2012), only four countries are currently producing commercially significant quantities of CSG: the USA, Canada, Australia and China. A search was undertaken of publications by relevant government agencies and industry associations in the USA, Canada and Australia. An equivalent search was also made in the UK, which has a nascent shale gas industry.

2.1 International

IPIECA (International Petroleum Industry Environmental Conservation Association), a London based organisation which describes itself as 'the global oil and gas industry association for environmental and social issues', published the second edition of its *Petroleum industry guidelines for reporting greenhouse gas emissions* in May 2011. This publication is essentially an elaboration and narrowing of the scope of the *Greenhouse gas protocol*, to provide guidelines that are consistent with the *Protocol* but specifically addressed to the needs of the oil and gas industry. It is concerned with reporting, not with measurement and estimation, and thus contains no details about particular emission sources. For that, the document refers to the API *Compendium*. The relationship between the two (and another IPIECA document) is described in the following terms:

> These *Guidelines* have been developed as a complement to the *Compendium* and the IPIECA *Sustainability Guidance*. While the *Compendium* focuses on GHG emissions estimation methodologies for industry sources (how to calculate emissions), the *Guidelines* primarily address GHG accounting and reporting (how to report emissions) for the GHG indicators identified in the *Sustainability Guidance*. Together, these three publications provide a comprehensive set of guidance for the estimation, accounting and reporting of petroleum industry GHG emissions. (IPIECA 2011, p. 1–2)

2.2 Canada

The Canadian Association of Petroleum Producers is the counterpart of the API and of the APPEA in Australia. In 2004 it published a detailed inventory of all greenhouse gas emissions from oil and gas production in Canada in 2000, prepared by the consultancy company Clearstone Engineering Ltd. The report is entirely confined to conventional petroleum and natural gas production and contains no reference to CSG (termed coal bed methane in North America). It does not reference the API *Compendium* and, based on the date of publication, appears to have been produced at about the same time, and in parallel with, the *Compendium*.

The most recent Canadian National Inventory Report, for 2009, produced by Environment Canada, relies on the 2004 report by Clearstone Engineering, pro-rating estimates in that report to 2009 output volumes.

A search of the websites of both Environment Canada and the Canadian Association of Petroleum Producers identified no documents dealing specifically with emissions associated with coal seam gas (coal bed methane) production.

2.3 USA

The USA is the source of the overwhelming bulk of published literature on emissions from gas production, including production of conventional dry natural gas, gas associated with crude oil production, tight gas, shale gas and coal bed methane. This literature includes methodologies for estimating and measuring emissions, inventories of emissions, and a more general academic literature on life cycle emissions from use of gas.

The key industry methodology document for oil and gas emissions is the API *Compendium*. The most recent edition (2009) contains specific references to coal bed methane as an alternative source of natural gas (Chapter 2); Table 2-3 lists possible emission sources, including both combustion and fugitive (in the broad sense of the term) emissions. However, the methodologies specified in Chapters 5 and 6 for these various individual sources are in all cases identical with the methodologies for the corresponding sources of emissions from conventional natural gas production. These methodologies include an equipment level average emission factor approach (Section 6.1.2). These are the methodologies to which Division 3.3.6 of the *Measurement determination* refers. Their key feature is that the default emission factors (for example, for leaks from wellheads, compressors and gathering pipelines) are all based on research publications from the 1990s — that is, well before the start of commercial coal bed methane production (see, for example, Tables 6-4 and C-14 of the *Compendium*).

It is clear that the *Compendium* has not adequately kept up with the very rapid development of gas production from both shale gas and CSG. In the USA, shale gas has become much more important than CSG as a source of unconventional gas. In 2009 these two sources accounted respectively for 13% and 7% of total US gas production (US EIA 2012a); recent projections (the EIA apparently has a delay of about two years in compiling actual production statistics for shale gas and CSG) are that by 2011 the shale gas share had risen to 30%, while CSG remained at 8% (US EIA 2012b). It is undoubtedly this rapid growth in shale gas product which has elicited, in the past year or so, such a high level of interest in emissions from shale gas, as expressed in the academic literature and in the wider public media.

It is fairly clear that the rise of shale gas production has also been an important incentive for the changes to both national emissions methodologies and guidelines for industry reporting introduced by the US EPA over the last couple of years. In all cases, these methodologies and guidelines promulgate a single set of approaches covering all forms of gas production. However, within the overall approach, some individual activities and processes are more widely used or more emissions intensive, or both, in the case of shale gas, compared with conventional gas, and the methodologies and guidelines make specific reference to shale gas production. In contrast, and undoubtedly reflecting its lesser relative importance in the USA, there are few references to coal bed methane.

The US literature is examined in the next section. It contains first a short summary of the general academic literature, followed by a description of the changes in inventory methodology introduced by the US EPA, and ends with a detailed account of the parts of the proposed new greenhouse gas reporting guidelines for the oil and gas industry which deal with gas field production.

3. US literature

3.1 Academic literature

The academic papers seek to estimate emissions per unit of gas supplied to final consumers from the full range of energy combustion and fugitive emission sources (though generally placing more emphasis on the latter than the former) in the upstream supply chain. They make no claim to have the status of inventories, but are meta-analysis, using primary data selected from a variety of sources and assembled to give a single life cycle emissions intensity figure.

The papers which have gained the greatest publicity are those by Cornell scientists Howarth et al. (2011, 2012). They explicitly assume a high rate of methane venting during shale gas well completion (1.%, compared with 0.01% for conventional gas). Their paper makes clear that this figure applies to well completion following hydraulic fracturing and assumes that all the methane emitted during this process is vented to the atmosphere and none is either collected for processing to pipeline gas or flared. This is contrary to industry best practice and to gas field practice mandated by some US states. The authors also assume additional methane emissions amounting to between 0.3% and 1.9% for routine venting and equipment leaks at well sites and from gathering pipelines. This estimate is referenced to a paper dealing with production from conventional gas fields and may, at least to some extent, reflect ageing infrastructure and superseded technologies and practices.

The emission estimates by Howarth et al. (2011) exceed those of a number of other US studies, many of which are conveniently referenced and summarised in Howarth et al. (2012). Fellow Cornell scientists, Cathles et al. (2011), specifically criticise the estimate of venting during well completion, arguing that methane loss during gas well completion using modern techniques to capture or flare gas 'is, or could be, at least 10 times lower than [Howarth et al.'s] estimate of 1.9 per cent'. Howarth et al. (2012) is a rejoinder to this criticism. Neither side in this particular debate makes further comment on the original estimate by Howarth et al. (2011) of routine venting and equipment leaks.

What can be concluded from this debate is that it cannot and will not be resolved until there are more and better field observations of actual gas field production practices and measurements of actual methane emissions. This conclusion applies, *a fortiori*, to any arguments that the high US estimates for shale gas production emissions should be applied to Australian CSG production. Strong in principle arguments can be advanced for why Australian practices are different and produce lower emissions, but only actual observations and measurements can bring the debates to resolution.

In the US, the EPA has become heavily involved in resolution of this issue through several different streams of work. These are examined in the remainder of this section.

3.2 The US Greenhouse Gas Inventory

The EPA is responsible for compiling the US national greenhouse gas inventory. The estimate of emissions from gas production underwent significant revisions in the 2009 inventory. The revisions relate to IPCC source Category 1B2b Natural Gas Systems. The EPA divides this source category into four sub-system components: field production, processing, transmission and storage, and distribution. This paper describes only changes to estimates of emissions from field production.

Three changes to the estimation of emissions of methane from field production were made in the 2009 inventory (US EPA 2011a).

- **IMPROVED ESTIMATE OF EMISSIONS FROM GAS WELL CLEANUPS (LIQUIDS UNLOADING).** This relates to wells with joint production of condensate. It may be relevant to some conventional gas wells in Australia (for example, some wells in the Cooper Basin) but is not relevant to CSG wells.
- **GAS WELL COMPLETIONS WITH HYDRAULIC FRACTURING**. This is relevant to CSG wells that use hydraulic fracturing.
- **GAS WELL RE-COMPLETIONS (WORKOVERS) WITH HYDRAULIC FRACTURING**. This, too, is or (more precisely, given that most wells have been only recently completed) will be relevant to CSG.

The basis for making these changes is explained in a document supporting the development of regulations for reporting emissions from the oil and gas industry under the Greenhouse Gas Reporting Program (US EPA 2011c), which is discussed below. Emission factors for well completions and well workovers with hydraulic fracturing were obtained from data reported publicly by gas producers at technical workshops organised under the EPA’s Natural Gas STAR program. Activity data — that is, the numbers of well completions and workovers, with and without capture or flaring of the released methane — were obtained from a variety of sources. These figures (but not the emission factors) have been criticised as too high by the industry (see below).

The overall effect of these changes was a very large increase (more than doubling for some years) in the estimate of methane emissions from natural gas systems. For example, the effect of the changes, when the estimate of natural gas production emissions in 2006 was recalculated, was to increase emissions from 90 to 198 Mt CO_2-e (US EPA 2011a).

These changes were used again in the 2010 inventory (US EPA 2012) with unchanged emission factors for each activity. In both inventories the new sources were added to a number of sources already included in the methodology, emission factors for which were in most cases derived from a 1996 study for the EPA and the Gas Research Institute (EPA/GRI 1996). Annex 3 to the 2010 inventory contains a detailed listing of the emission factors used for each emission source enumerated in the field production component of the natural gas system. The complete list of sources, which is structured in a three-level hierarchy, is as follows. Note that not all of these sources are relevant to CSG production. Sources related to conventional gas production with associated condensate are clearly not relevant and are identified as such in the list below; some of the other sources may also not be relevant, or not used in CSG production in Australia.

Normal fugitives	
Gas wells	
Associated gas wells	Not relevant
Non- associated gas wells (less wells with hydraulic fracturing)	
Gas wells with hydraulic fracturing	
Field separation equipment	
Heaters	Not relevant
Separators	Not relevant
Dehydrators	
Meters/piping	
Gathering compressors	
Small reciprocating compressors	
Large reciprocating compressors	
Large reciprocating stations	
Pipeline leaks	
Vented and combusted	
Drilling and well completion	
Gas well completions without hydraulic fracturing	
Gas well completions with hydraulic fracturing	
Well drilling	
Produced water from coal bed methane wells	
Normal operations	
Pneumatic device vents	
Chemical injection pumps	
Kimray pumps	
Dehydrator vents	
Condensate tank vents	
Condensate tanks without control devices	Not relevant
Condensate tanks with control devices	Not relevant
Compressor exhaust vented	
Gas engines	
Well workovers	
Gas wells without hydraulic fracturing	
Gas wells with hydraulic fracturing	
Gas wells with liquids unloading	Not relevant
Blowdowns	
Vessel BD	
Pipeline BD	
Compressor BD	
Compressor starts	
Upsets	
Pressure relief valves	
Mishaps	
Offshore	
Offshore water gas platforms	Not relevant
Deepwater gas platforms	Not relevant

The inventory Annex specifies separate emission factors, mostly expressed in units of methane volume emitted per item per year. For each source, emission factors are listed separately for six regions of the USA. The numbers of individual emission factor values is therefore exceedingly large.

In the total inventory, excluding sources which are not relevant to CSG production, the sources which account for the majority of methane emissions are, together with their share of relevant emissions, the following.

Normal operations: pneumatic devices and pumps	41%
Well workovers with hydraulic fracturing	19%
Well completions with hydraulic fracturing	16%
Pipeline leaks	8%
Gas engine compressor exhaust	7%
Dehydrators	3%
Gathering compressor leaks	2%
Produced water from coal bed methane wells	2%

It is our understanding that the need to use wellhead pneumatic devices and pumps in CSG production is limited, because in most wells the gas is produced under pressure. Hence, on the basis of the US emissions inventory, well completions and workovers with hydraulic fracturing are likely to be the largest sources of methane emissions, followed by pipeline leaks.

In assessing the relative significance of these figures, it is essential to bear in mind the relative production volumes from the various types of gas resource. The 41% from normal operations is likely to be sourced mainly from conventional gas production, which accounted for about two-thirds of total US gas production in 2010. Hydraulic fracturing predominates in shale gas production, which supplied around a quarter of total gas in 2010, while CSG supplied only 7% or so. It follows that produced water from coal bed methane wells is a very much more important source of emissions from CSG than the above percentages would, at first, suggest.

The approximate annual emissions factors used for the above sources, expressed in terms of mass of methane, averaged over the regions and converted to metric units, are as follows.

Normal operations: pneumatic devices and pumps	13 kg per device
Well workovers with hydraulic fracturing	177 t
Well completions with hydraulic fracturing	177 t
Pipeline leaks	0.65 kg/km
Gas engine compressor exhaust	5 g/h
Dehydrators	0.3 g/t methane throughput
Gathering compressor leaks	5 kg per day per compressor
Produced water from coal bed methane wells	0.64 g/L water *or* 640 kg per well

In the case of well completions and workovers, the methodology allows for a deduction for methane which is either flared or captured as product gas.

Total net methane emissions depend not only on the emission factor for the process or piece of equipment, but also on the activity levels. The API and America's Natural Gas Alliance (ANGA) have recently released a joint report (API/ANGA 2012) which criticises the 2010 emissions inventory figures. The ground for the criticism is not the emission factors but the activity data which, based on a survey of members of the two organisations, is said to be too high. In particular, the report says that the rate of re-fractures in existing wells is much lower than assumed by the EPA, thus reducing the estimate of emissions from workovers with hydraulic fracturing.

On the other hand, some of the academic work summarised above has criticised the EPA inventory figures as over-estimating the volume of methane which is flared or captured during completions and workovers, thereby underestimating net total emissions.

3.3 The US Greenhouse Gas Reporting Program

In 2008 the EPA started work on developing a GHG Reporting Program under the Clean Air Act. The new Program became effective on 29 December 2009 and included reporting requirements for facilities and suppliers in 32 source categories. These source categories did not include equipment leaks and vented greenhouse gas emissions from petroleum and natural gas systems. In November 2010 the EPA promulgated a regulation to require monitoring and reporting of greenhouse gas emissions from petroleum and natural gas systems, having the effect of adding this source category to the list of source categories already required to report greenhouse gas emissions. The new Rule is 40 CFR Part 98 subpart W (US EPA 2010). In December 2011, extensive though mostly minor technical corrections and revisions came into effect (US EPA 2011b). Some further minor technical corrections came into effect in May 2012.

Decisions as to which individual emission sources are required to be reported, and which methodology is required to be used (direct measurement of default emission factors), were largely based on an analysis of the relevant importance of the various sources, derived from the national emissions inventory as shown in the previous section. This is detailed in the *Background technical support document* (US EPA 2011c). As explained below, some sources included in the inventory, notably pipeline leaks, were excluded from the reporting obligation, presumably on the basis that direct measurement would be infeasible (or at least very complex and costly and an unwarranted imposition on individual reporters) and that available measurement data are not sufficiently robust to support use of a default emission factor or factors.

3.3.1 Scope of coverage

The broad source categories covered by 40 CFR Part 98 subpart W are as follows.

- Offshore petroleum and natural gas production
- Onshore petroleum and natural gas production
- Onshore natural gas processing
- Onshore natural gas transmission and compression
- Underground natural gas storage
- Liquefied natural gas (LNG) storage
- LNG import and export equipment
- Natural gas distribution.

Within each major source category there are a number of industry segments that generally correspond to the source components in the US inventory, discussed above. A reporting entity is required to report its emissions from each industry segment if it is engaged in the segment. There is not a close correspondence between the EPA's industry segments and the equipment types defined in the API *Compendium* and taken up under Method 2 of the *Measurement determination*. The industry segments with which this review is concerned are confined to the second source component listed above, that is, 'onshore petroleum and natural gas production'.

Before discussing the individual segments, two important points should be noted. Firstly, under both source categories, the Rule explicitly excludes 'reporting of emissions from gathering lines and boosting stations', stating that 'these sources are not currently covered by subpart W' (US EPA 2010, p. 74462). Secondly, it is clearly implied, by repeated mentions, that the rule covers production of both conventional gas and also the various categories of unconventional gas, including tight gas, coal bed methane (CSG in Australian terminology) and shale gas (see, for example, US EPA 2011b, p. 80557 and p. 80568).

Subpart 98.232 contains a lengthy list of industry segments (equipment types) for which emissions of CO_2, CH_4 and N_2O must be reported. Those relevant to this review, that is, including only those segments related to the production and processing of gas and excluding segments related to the production of petroleum liquids, are as follows.

For onshore petroleum and natural gas production:

- (1) Natural gas pneumatic device venting.
- (3) Natural gas driven pneumatic pump venting.
- (5) Gas well venting during well completions without hydraulic fracturing.
- (6) Gas well venting during well completions with hydraulic fracturing.
- (7) Gas well venting during well workovers without hydraulic fracturing.
- (8) Gas well venting during well workovers with hydraulic fracturing.
- (10) Storage tanks vented emissions from produced hydrocarbons.
- (11) Reciprocating compressor rod packing venting.
- (14) Dehydrator vents.
- (19) Centrifugal compressor venting.
- (21) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps).

(The numbers are those contained in the relevant paragraphs of subpart 98.232 of the Rule.)

3.3.2 Methods specified

Introduction

Subpart 98.233 specifies methods which must be used to calculate emissions from most but not all of these industry segments.

Where methods are specified they fall into three groups. The first two groups are for emissions from equipment components or operations from which emissions are known to occur, and of which there is at least some knowledge of performance characteristics. The two methodologies are:

- those that use generic equipment type emission factors;
- those that require direct measurement (or calculation from measurements of closely related parameters).

The third group of methods is for leaks.

Methods which specify emission factors

For each of the segments listed below the EPA specifies a method which estimates emissions based on a fixed rate of emissions per piece of equipment used by the segment. Emissions depend only on this emission factor and the number of hours in the year for which the equipment is operating. Emissions are independent of the rate of flow of gas through the equipment. The method therefore differs from both methods specified in Division 3.3.6 of the *Measurement determination*, under which emissions depend on throughput volumes. (Note, however, that there is an element of proportionality in the EPA methods, in that larger throughput volumes will require more items of each type of equipment to operate in parallel.) On the other hand, Section 3.84 of Division 3.3.9 of the *Measurement determination* references the API *Compendium*, which specifies methods based either on numbers of individual pieces of equipment or, in the case of non-routine events, on the numbers of individual events. These methods are consistent with those used by the EPA (though the emission factors are not necessarily the same).

The segments for which emission factors are specified by the EPA are the following. The values listed here are the revised values given in US EPA (2011b).

- **Natural gas driven pneumatic device venting (paragraph (a) of section 98.233)**.

  The following emission factors are specified.

  In eastern US

'Low continuous bleed'	26 g/h per device
'High continuous bleed'	690 g/h per device
Intermittent bleed	250 g/h per device

  In western US

'Low continuous bleed'	33 g/h per device
'High continuous bleed'	880 g/h per device
Intermittent bleed	320 g/h per device

  (Neither 'low' nor 'high' are defined.)

- **Natural gas driven pneumatic pump venting (paragraph (b) of section 98.233)**.

  Emission factor specified is:

  190 g/h per pump

- **Dehydrator vents.**

  For glycol dehydrators with throughput of less than 0.4 million scf per day, emission factor specified is:

  > 1.4 t methane per dehydrator per year at 68^{o}F and 14.7 psia

- **Gas well venting during well completions and workovers without hydraulic fracturing.**

  Emission factor specified is:

  > 58 kg per well completion/workover

- **Centrifugal compressor wet seal oil degassing vents associated with onshore petroleum and natural gas production.**

  Emission factors specified are:

  > 223 kg methane per compressor per year at 68^{o}F and 14.7 psia

- **Reciprocating compressor venting in onshore oil and gas production.**

  Emission factors specified are:

  > 180 kg methane per compressor per year at 68^{o}F and 14.7 psia

3.3.3 Methods which require volume measurement

The segments for which measurement of either vented volume flow rates (either from every source or from a representative sample of source wells) or other volumes are required to be measured for the following industry segments.

- Dehydrators with throughput greater than 0.4 million scf per day.
- Gas well venting during well completions and workovers from hydraulic fracturing (flow rates may be measured directly or estimated indirectly from orifice cross-sectional area and pressure differential data).
- Blowdown vent stacks (static volume measurement is required, not flow rates).
- Well testing venting and flaring.

3.3.4 Methods for leaks

Leaks at gas processing and other downstream facilities

For generalised leaks at gas processing facilities, a combined approach is specified in subpart 98.233, paragraph (q). This requirement does not apply to gas production activities. It is also stated that:

> This paragraph (q) applies to emissions sources in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (q) and do not need to be reported. (p. 74501)

For entities reporting emissions from gas processing facilities, that is, not covered by the exclusions above, subpart 98.234, paragraph (a) specifies methodologies that must be used to detect leaks. These include:

- optical gas imaging;
- EPA Method 21, an EPA approved method for measuring leakage of VOCs from process equipment (see http://www.epa.gov/ttn/emc/methods/method21.html);
- infrared laser beam illumination;
- acoustic leak detection.

When a leak is detected, the following emissions factors should be used.

Equipment component	Emission factor (scf per hour)	
	Compressor components	Non-compressor component
Valve, per component	14.84	6.42
Connector, per component	5.59	5.71
Open-ended line, per component	17.27	11.27
Pressure relief valve, per component	39.66	2.01
Meter	19.33	2.93

Leaks at gas production facilities

For entities reporting emissions from gas production facilities, there is no requirement to detect leakage. A method using generic default emission factors is specified. (This method also applies to leakage from downstream gas facilities, including LNG storage, LNG export equipment and underground natural gas storage. It also applies to leaks at gas processing facilities where no leaks are detected.) The method has the same exclusions as the previous method, that is, streams with gas content of less than 10% and tubing systems of less than half inch diameter.

For each category of equipment at a facility, leakage emissions of natural gas are to be calculated as the product of the default count of pieces of each equipment type and the default gas leakage rate for the equipment type. Default values are specified in Tables W-1 to W-7 at the end of 40 CFR Part 98 subpart W. Two sets of values are specified for both emission factors and equipment component counts — one set for the eastern USA and one set for the western USA. A definition, by State, of east and west is provided; the Mississippi River is the rough dividing line between the two.

Emission factor values for gas production facilities are as follows.

Equipment component	Emission factor (scf per hour)	
	Eastern USA	Western USA
Valve, per component	0.640	2.903
Connector, per component	0.083	0.396
Open-ended line, per component	1.46	0.748
Pressure relief valve, per component	0.97	4.631
Low continuous bleed pneumatic device vents, per device	1.39	1.77
High continuous bleed pneumatic device vents, per device	37.3	47.4
Intermittent bleed pneumatic device vents, per device	13.5	17.1
Pneumatic pumps, per pump	10.3	10.3

3.3.5 Comparison between US EPA and AIP

The new EPA Regulations and the older AIP *Compendium* differ markedly in respect of both the categories of equipment and the methodologies, with only limited comparisons between the two being possible. In particular, as described above, the EPA prescribes direct measurement for a number of emission sources for which the AIP provides default emission factors. The following table provides a comparison for those sources for which both specify equipment based emission factors. This comparison should be regarded as indicative only, because in many cases it is difficult to be certain that the definitions of equipment type are directly comparable. As in the rest of this report, information is provided only for those emissions associated with gas production. Emission sources associated with petroleum liquids production are not included.

Equipment type	Emission factor (scfy CH_4 per item)	
	AIP *Compendium*	EPA 40 CFR Part 98
Gas wellheads	8,217	
Small reciprocating gas compressor	97,023	9,630
Large reciprocating gas compressor	5,550,000	
Large reciprocating gas compressor stations	8,247	
Centrifugal compressors (used in gas processing, not production)	4,087,270	12,000,000
Meters/piping	16,073	169,331
Dehydrators	32,561	74,500

In addition, and most importantly in the context of this review, the *Compendium* provides default emission factors for methane and CO_2 emissions from gathering pipelines, expressed in units of mass of gas per unit length of pipeline. As noted at the outset, the EPA explicitly excludes leakage emissions from this source.

4. Australian research on fugitive methane emissions from CSG production

There is at present no published data on methane emissions from CSG production in Australia. Apart from any work which may have been undertaken in house by individual CSG producers, there is also no systematic program currently underway to measure emissions. However, two of Australia's leading research organisations are currently developing proposals for programs to study fugitive emissions from CSG production.

4.1 CSIRO

The Energy Technology Division of CSIRO has over two decades' experience in measuring methane emissions from coal mining activities. Measurements made by CSIRO in the early 1990s provided the basis for the original methodology for estimating fugitive methane emissions from coal mining in Australia and still form an important underpinning for the estimation of emissions from this source. Staff from this Division are currently developing a research proposal to investigate fugitive emissions from CSG production, working jointly with two other CSIRO Divisions: Marine and Atmospheric Research, and Earth Science and Resource Engineering. The aim will be to integrate local measurement of methane concentrations adjacent to production facilities, with broader regional measurements of atmospheric methane levels.

The local measurements will be informed by the petroleum engineering expertise of staff in Earth Science and Resource Engineering. The atmospheric modelling expertise of staff in Marine and Atmospheric Research will be used to reconcile the regional measurements with the local, taking into account methane emissions from other sources such as coal mines and feedlots. The objectives of the research will be to determine the levels of methane emissions from well completions with and without hydraulic fracturing, to identify other important sources of methane emissions from CSG production, and to estimate the overall contribution of CSG production to observed levels of atmospheric methane.

4.2 University of Queensland

The recently established Centre for Coal Seam Gas (CCSG) is one of seven research centres making up the Sustainable Minerals Institute at the University of Queensland. On its website the Centre says that its vision is:

> to be a world leading centre of excellence that serves the research and educational needs of stakeholders in the Australian CSG/LNG industry. CCSG supports leading practice policy development and helps ensure that Australia becomes the primary source of new knowledge, technology and skilled graduates for the industry as it develops world-wide.
> http://www.ccsg.uq.edu.au/AboutCCSG/VisionMissionObjectives.aspx

The Centre, and the Sustainable Minerals Institute as a whole, bring together researchers from a variety of disciplines across the University to undertake research to their areas of focus. In a fact sheet the Centre states that its research will be interdisciplinary in character, incorporating technical, engineering, economic and social science perspectives, and will be organised into the following program areas.

- Water, including hydrogeology, water treatment and utilisation.
- Social performance, community and environmental impact.
- Coal seam geophysics and geochemistry.
- Characterisation and engineering of CSG reservoirs.

In communication with staff of the Centre, pitt&sherry was advised that a project proposal is being prepared for consideration by the Centre, with the objective of undertaking a comparative assessment of life cycle greenhouse gas emissions from extraction to power generation for CSG and open cut coal mines in Queensland.

5. Conclusions

Uncontrolled fugitive (leakage) emissions from unconventional gas production have been a matter of considerable public controversy in the USA for several years. They are also a growing source of controversy in Australia. In the USA there is apparently a significant body of public data about emission factors for what are understood to be the more important individual sources of emissions from unconventional gas production. There is also an appreciable body of relevant activity data, though the accuracy of this information has been criticised by the industry.

In 2009 the US National greenhouse gas inventory was amended to include an estimate of methane emissions from well completions and well workovers using hydraulic fracturing at unconventional gas wells. The estimation methodology does not distinguish between shale gas and CSG. Subsequently, specific reporting requirements relating to this source have been included in the requirements applying to the oil and gas industry under the Greenhouse Gas Reporting Program. When the reporting regulations come into effect, a very large body of data will become available.

The large and growing body of real data on emissions from unconventional gas production in the USA, though still far from comprehensive (and seemingly largely ignored in much of the somewhat polemical academic literature) is in marked contrast to the situation in Australia. There is effectively no public information about methane emissions associated with unconventional gas production in Australia. This is a matter of some public policy concern, given the projected large growth in production of CSG. Unlike the USA, where shale gas accounts for the majority of unconventional gas production, CSG at present accounts for all Australian production of unconventional gas. Production processes for CSG differ significantly from those used for shale gas. There may also be differences with respect to gathering, compression, etc. For these reasons, quite apart from any considerations of national responsibility, it would be highly desirable for more and better information about methane emissions associated with CSG production to be gathered and made publicly available. It may also be appropriate, given the significant changes in methodologies used in the USA, for methodologies for estimating fugitive methane emissions from conventional oil and gas production to be reviewed.

We suggest that a four-step process might be appropriate.

1. Undertake a rough assessment of the possible relative magnitude of the various individual sources. As described above, this was the approach followed in the USA in developing the reporting requirements under the Greenhouse Gas Reporting Program. Given the lack of Australian data, it may be necessary to use default or implicit emission factors from the US for this first pass assessment, notwithstanding the significant qualifications as to their applicability to Australia.

2. Obtain sample measurements of emissions from the sources identified in step (1) as likely to be the most important.

3. After analysing the results of the sample measurements, decide what amendments should be made to the NGERS reporting requirements. The key issue will be whether to use default emission factors for all individual sources, to require direct measurement for the more important sources, as in the US reporting rules and, if so, which sources should be directly measured.

4. Prepare amendments to the *Measurement determination*.

6. References

Alberta Energy 2012, Natural gas publications and maps, http://www.energy.alberta.ca/NaturalGas/940.asp

API (American Petroleum Institute) 2004, *Compendium of greenhouse gas emissions methodologies for the oil and natural gas industry*, http://www.api.org/environment-health-and-safety/climate-change/whats-new/compendium-ghg-methodologies-oil-and-gas-industry.aspx

API/ANGA 2012, *Characterizing pivotal sources of methane emissions from unconventional natural gas production: summary and analysis of API and ANGA survey responses*, http://www.anga.us/media-room/press-releases/2012/06/methane-emissions-from-hydraulic-fracturing-of-unconventional-natural-gas-wells-are-half-what-epa-estimated.

Australian Government 2012, *National greenhouse and energy reporting (measurement) determination 2008*, http://www.comlaw.gov.au/Details/F2012C00472

Cathles, LM, Brown, L, Taan, M & Hunter, L 2011, 'A commentary on "The greenhouse-gas footprint of natural gas in shale formations" by RW Howarth, R Santoro & Anthony Ingraffea', *Climatic Change*, DOI 10.1007/s10584-011-0333-0.

EPA/GRI 1996, *Methane emissions from the natural gas industry*, prepared by M Harrison, T Shires, J Wessels, and R Cowgill, eds., Radian International LLC for National Risk Management Research Laboratory, Air Pollution Prevention and Control Division, Research Triangle Park, NC. EPA-600/R-96-080a, http://www.epa.gov/gasstar/tools/related.html.

Howarth, RW, Santoro, R & Ingraffea, A 2011, 'Methane and the greenhouse gas footprint of natural gas from shale formations', *Climatic Change*, 106:679–690 DOI 10.1007/s10584-011-0061-5 (letter).

——2012, 'Venting and leaking of methane from shale gas development: response to Cathles et al.' *Climatic Change*, DOI 10.1007/s10584-012-0401-0.

IEA 2012, *Golden rules for a golden age of gas: world energy outlook*, special report on unconventional gas.

IPIECA 2011, *Petroleum industry guidelines for reporting greenhouse gas* emissions, 2nd ed., May 2011, http://www.ipieca.org/sites/default/files/publications/GHG_reporting_guide_FINAL.pdf

Queensland Government 2012, *Coal seam gas production January 2005 to December 2012*, http://mines.industry.qld.gov.au/mining/production-reserves-statistics.htm.

US EIA (Energy Information Administration) 2012a, *Natural gas gross withdrawals and production*, http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm.

——2012b, *Annual energy outlook 2011*, Table 14,Oil and gas supply, http://www.eia.gov/forecasts/archive/aeo11/source_natural_gas.cfm.

US EPA (Environmental Protection Agency) 2010, 'Mandatory reporting of greenhouse gases: petroleum and natural gas systems', *Federal Register*, Vol. 75, No. 229, pp. 74458–74515.

——2011a, *Inventory of US greenhouse gas emissions and sinks: 1990–2009*, http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/archive.html

——2011b, 'Mandatory reporting of greenhouse gases: technical Revisions to the petroleum and natural gas systems category of the Greenhouse Gas Reporting Rule', *Federal Register*, Vol. 76, No. 247, pp. 80554–80595.

——2011c, *Greenhouse gas emissions reporting from the petroleum and natural gas industry: background technical support document*, http://epa.gov/climatechange/emissions/subpart/w.html

——2012, *Inventory of US greenhouse gas emissions and sinks: 1990–2010*.

transport infrastructure | community infrastructure | industrial infrastructure | climate change

pitt&sherry

Brisbane
3rd Floor
87 Wickham Terrace
PO Box 825
Spring Hill QLD 4004
T: (07) 3832 7455
F: (07) 3832 7466

Canberra
1st Floor
20 Franklin Street
PO Box 4442
Manuka ACT 2603
T: (02) 6295 2100
F: (02) 6260 6555

Devonport
1st Floor
35 Oldaker Street
PO Box 836
Devonport Tasmania 7310
T: (03) 6424 1641
F: (03) 6424 9215

Hobart
199 Macquarie Street
PO Box 94
Hobart Tasmania 7001
T: (03) 6210 1400
F: (03) 6223 1299

Hobart Building Surveying
T: (03) 6210 1476
F: (03) 6223 7017

Launceston
4th Floor
113 – 115 Cimitiere Street
PO Box 1409
Launceston Tasmania 7250
T: (03) 6323 1900
F: (03) 6334 4651

Melbourne
3rd Floor
147 Eastern Road
PO Box 259
South Melbourne Victoria 3205
T: (03) 9682 5290
F: (03) 9682 5292

sustainable*thinking*®

E: info@pittsh.com.au
www.pittsh.com.au

incorporated as
Pitt and Sherry (Operations) Pty Ltd
ABN 67 140 184 309

BRW. CLIENT CHOICE AWARDS 2010
australia's best professional service firms

pitt&sherry - Proud winner of
"Best Consulting Engineering Firm
Revenue under $50M"

CONSULT AUSTRALIA
Member Firm