

## Coal Seam Gas Emissions: Facts, Challenges and Questions

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### Structure

Executive Summary  
Introduction

- 1. CSG production, processing and consumption**
  - 1.1 CSG production
  - 1.2 Gas processing and consumption
  - 1.3 Gas transportation
- 2. Australia's CSG industry**
  - 2.1 Gas consumption in eastern Australia
  - 2.2 Gas production for LNG export
- 3. Greenhouse gas emissions from CSG**
  - 3.1 Comparing CSG and conventional gas: from production to pipeline
  - 3.2 Comparing CSG and conventional gas: full life cycle from extraction to consumption
  - 3.3 Emissions from power generation: comparing gas and coal
- 4. Impact of CSG on Australia's greenhouse gas emissions**
- 5. Climate policy for CSG production and consumption**
  - 5.1 Emissions minimization in CSG production
  - 5.2 Emissions reduction in domestic electricity generation

### Executive Summary

Under current policy settings, coal seam gas (CSG) is likely to play a greater role both in domestic energy production, and, exported as liquefied natural gas (LNG), in meeting fast-growing regional demand for gas. If all committed and probable LNG projects go ahead, CSG production could increase nine-fold by 2020.

Methane (the main component of natural gas and of CSG) is considered to be a 'bridging fuel' between coal-fired power and the necessary zero/negative-emissions energy sources. At combustion, electricity produced from methane generates less greenhouse gas pollution than electricity produced from coal.

However, recent research from the United States has suggested that the emissions associated with unconventional gas production may be far higher than previously believed. As methane is a greenhouse gas 25 times more potent than carbon dioxide (CO<sub>2</sub>) over a 100-year timeframe, methane leakage can significantly raise the life-cycle emissions of gas consumption and cancel part or all of its emissions advantage over coal. The techniques used to extract unconventional gas – natural gas trapped in coal seams, tight sandstone or shale formations – may allow significant methane leakage ('fugitive emissions'<sup>\*</sup>). In addition, more methane may be leaking from gas processing and transport infrastructure than has been estimated by producers to-date.

Production emissions from Australian CSG have not been well researched. There are reasons to expect that

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\* It should be noted that in the IPCC Guidelines used for reporting national greenhouse gas inventories, gas venting, flaring, uncontrolled leakage for gas distribution pipelines, and methane emissions from coal mining are categorised as elements of a larger source category called Fugitive Energy. In the oil and gas industry, however, the term 'fugitive emissions' has a more limited meaning, applied only to uncontrolled leakage of gas from wells and gathering pipeline systems. By definition, such emissions are not directly controllable and cannot be directly measured, whereas emissions from venting and flaring are both controllable and measurable. This is a potential source of confusion in the debate over CSG emissions.

fugitive emissions from Australian CSG could be lower than those of US shale gas production. These include differences in the production process, regulatory framework, geology, equipment and infrastructure.

In addition, the market value of gas, and, from 1 July 2012, the cost imposed by the carbon price, provide financial incentives for CSG producers to minimise their emissions. However, current methods for estimating production emissions are based on out-dated methods for conventional gas production, and there is no publicly available information on the accuracy of producers' emissions estimates. This undermines the ability of Australia's existing regulatory regime to drive improved practice.

Higher CSG production emissions not only increase the life-cycle emissions of CSG consumption, they also increase the amount of emission reductions Australia needs to undertake domestically or internationally to meet a given pollution target. Higher domestic emissions would mean greater reliance on and investment in carbon offsets.<sup>x</sup>

This paper provides a range of possible CSG production emissions by taking the industry estimate of gas field fugitive emissions by Hardisty et al. (2012) from Worley Parsons as a low-end estimate, and the high end of the range proposed by Howarth et al. (2011) from Cornell University as a high-end estimate. Table ES1 shows these two estimates for emissions from CSG alongside estimates for conventional gas production from the Gippsland Basin (processed at Longford) and Cooper Basin (Moomba/Ballera).

**Table ES1**

*Estimated emissions from supplying gas into pipeline for domestic consumption (kt CO<sub>2</sub>-e/PJ gas supplied)*

Fuel cycle stage	Emission source category	Conventional gas		CSG	
		Cooper	Gippsland	High	Low
Production	Combustion	2.9	0.9	2.5	2.5
	Fugitive	0 <sup>(1)</sup>	0 <sup>(1)</sup>	16	3.4
Processing	Combustion	5.5	2.8	0 <sup>(2)</sup>	0 <sup>(2)</sup>
	Fugitive	17	0	0 <sup>(2)</sup>	0 <sup>(2)</sup>
Total emissions into pipeline		25.4	3.7	18.5	5.9

Combining the figures above with emissions from combustion of gas by final users (51.3 kt CO<sub>2</sub>-e/PJ) gives estimates of life cycle emissions of gas in eastern Australia shown in Table ES2. The average emission

<sup>x</sup> Under current policy settings Australia's carbon price will be determined by the international market post 2015. Higher emissions in Australia would not materially increase the cost of achieving a given target as Australia will largely be an international price taker. More emissions in Australia shift the balance of where emission reductions occur, i.e. higher CSG emissions in Australia mean companies must investment more elsewhere to limit pollution.

factor of black steaming coal combustion, for comparison, including full fuel cycle emissions arising from energy used to mine and transport coal and methane emissions from coal mines, is 92.8 CO<sub>2</sub>-e/PJ.<sup>1</sup>

**Table ES2**

*Life cycle emissions of conventional gas and CSG to power stations and retail consumers (kt CO<sub>2</sub>-e/PJ)*

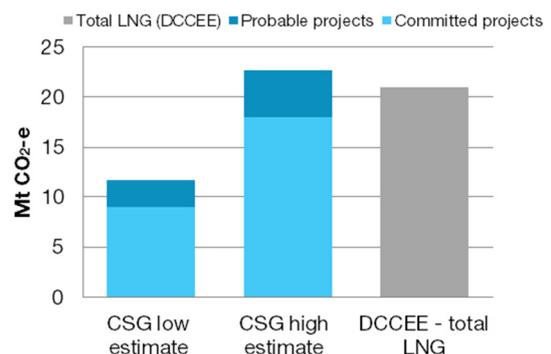
Gas type	Emissions level	To power station	To retail consumer
Conventional gas	High (Cooper)	77	87
	Low (Gippsland)	56	66
CSG	High	70	80
	Low	58	68

On the basis of these figures it cannot be concluded that CSG is significantly more emissions intensive than all conventional gas (or coal). However, it should also be recognised that the Cooper Basin gas fields are unusual in eastern Australia in having very high levels of CO<sub>2</sub> raw gas. Gippsland gas processed at Longford is much more representative of the bulk of conventional gas produced in eastern Australia. Comparing high end estimates from CSG emissions to Gippsland gas would indicate a more emissions intensive industry.

However, applying the high (Howarth et al.) and low (Hardisty et al.) estimates to projected CSG-LNG production shows that CSG emissions could add a substantial amount to Australia's total. By 2020, committed and probable LNG projects could drive additional CSG production emissions of 12-23Mt CO<sub>2</sub>-e (see Figure ES2, below). By way of comparison, the Department of Climate Change and Energy Efficiency estimated total fugitive emissions from the entire LNG industry, of which CSG is projected to make up 15 per cent, could be 21Mt CO<sub>2</sub>-e in 2020.

**Figure ES1**

*Projected emissions from committed and probable projects in 2020, compared with DCCEE's projected fugitive emissions from all LNG*



If Australian CSG is to play any constructive part in a transition to zero-emissions energy, it is vital that its life-cycle emissions are correctly measured and monitored, and minimised. This needs to start with independent, comprehensive research into the industry's *actual* emissions. This research should inform updated emissions calculations used in the National Greenhouse and Energy Reporting Scheme Technical Guidelines (NGERS Guidelines).

When combined with more accurate measurement, a robust price on greenhouse gas pollution will help ensure CSG producers pay for their emissions and encourage practices that minimise or at least offset emissions. However, where accurate emissions calculations are impractical it may also be necessary to regulate for best practice in technologies, actions and equipment. Regulation should be nationally consistent.

The carbon price mandated by the Clean Energy Act 2011 has the potential to encourage CSG producers to pay for, offset or reduce their emissions. However, in the absence of a predictable long-term carbon price, the uncertainty surrounding the future trajectory of prices will discourage optimal levels of investment in emissions minimisation. It should be recognised that the Coalition's climate policy also includes a pollution price. Under the Coalition plan, CSG production emissions would be included within the Emissions Reduction Fund, which covers companies required to report to the NGER Scheme. CSG producers could receive financial rewards for reducing their emissions below a baseline level and would pay a penalty if they exceed it. It is as yet unclear that the baseline and penalty would be set at levels high enough to drive emissions minimisation across the CSG industry.\*

Moreover, to ensure that CSG can act as a true 'bridging fuel', public policy must provide sufficient clarity and certainty about the long-term emissions requirements of new generation. Until carbon prices reflect the value of reducing emissions in the longer term, complementary measures are required. Stringent emissions performance standards for new power generators would avoid the construction of new power plants that could undermine national climate change mitigation goals and/or lead to stranded assets and higher costs in future. The Renewable Energy Target, the Clean Energy Finance Corporation and the proposed national Energy Savings Initiative are also crucial

policies for the transition to zero/negative emissions energy.

## Recommendations

1. The Commonwealth Government should immediately commission, with funding from the CSG-LNG industry, robust independent research into the emissions profile of CSG production in Australia, with a particular focus on emissions from CSG extraction including emissions after production ceases.
2. Emissions measurement and estimation methods in the NGERS Guidelines should be updated on the basis of the research findings.
3. Regulation of CSG production should be nationally harmonised, and should enforce best practices. Regulation is appropriate in the absence of bipartisan support for robust pollution pricing and for practices, technologies and equipment where accurate emissions measurements or estimates are lacking or impractical.
4. Introduce emissions performance standards for power generators. All non-peaking gas plants must be retrofitted to 0.2 tCO<sub>2</sub>-/MWh within 15 years after construction.<sup>2</sup>
5. In addition, under the Coalition's climate policy, CSG production emissions above best practice should be strongly penalised to incentivise investment in emissions reductions or offsets. Penalties should be set at levels consistent with reducing national emissions to the bipartisan supported 2020 target range.

This paper focuses only on the greenhouse gas implications of CSG production in Australia. There is widespread concern about other environmental, social and economic impacts resulting from the CSG boom. These are important, but they lie outside of The Climate Institute's area of expertise and the scope of this paper. Of course, any decisions concerning CSG development must take full and proper account of all relevant impacts, not just carbon pollution.

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\* The Coalition's climate policy proposes that companies producing emissions above a 'business as usual' baseline will pay a financial penalty, with penalties set in consultation with industry and provisions to ensure new entrants or 'business expansion at best practice' are not penalised. See *The Coalition's Direct Action Plan*.

## Introduction

Australia has vast reserves of unconventional natural gas (natural gas found in geological formations of low permeability such as coal seams, ‘tight’ sandstone or shale). Australia’s commercially recoverable reserves of coal seam gas (CSG) are estimated at 36,000 PJ or one-third of the country’s entire commercially recoverable gas reserves, and 80 per cent of eastern Australia’s gas reserves.<sup>3</sup> CSG reserves are concentrated primarily in Queensland, with significant reserves also in NSW. Extraction and consumption of coal seam gas, located in Queensland and New South Wales, has been undertaken since 1999.<sup>4</sup>

Now, production is increasing rapidly. As CSG replaces gradually declining reserves of conventional gas from the established Gippsland and Cooper Basin fields, Queensland as the major source of gas supply for eastern Australia. In the next few years there will be a further major increase in CSG production to supply four export LNG projects now under construction in Queensland.

Greater supply and consumption of CSG could have significant implications for Australia’s greenhouse gas emissions. Natural gas is widely considered a valuable ‘bridging fuel’ between coal-fired power generation and the zero/negative-emissions energy sources needed if the world is to avoid dangerous climate change.<sup>5</sup> Electricity produced from gas generates fewer greenhouse gas emissions than electricity produced from coal combustion, and has been generally considered cheaper than new renewable energy.

However, recent research from the United States suggests that the emissions associated with unconventional gas production may be significantly higher than previously believed. Given the role of Australian-produced CSG in domestic and international energy generation, it is critical that we understand the likely impact of CSG on net greenhouse gas emissions. This paper explores two key questions:

- + What might be the effect on Australia’s total emissions of the boom in CSG production?
- + How do we ensure that CSG does not lock in high emissions, but plays a constructive role in the transition to a zero/negative-emissions energy future?

This discussion focuses only on these questions. Other concerns relevant to CSG production, such as potential impacts on water resources or the displacement of farmland, are not covered. While these issues are of significant importance and must be fully addressed by policy makers, they are outside The Climate Institute’s area of expertise and the scope of this paper. Our aim here is not to resolve all of the issues of CSG development in Australia but to investigate its emissions, in the most rigorous way possible given the data available, and to suggest policy strategies to deal with this particular issue. The Climate Institute recognises that any decisions made on CSG must take all relevant economic, environmental and social issues into account.

# 1 CSG production, processing & consumption

## 1.1 CSG production

Like conventional natural gas and shale gas, CSG is predominantly methane (CSG is also known as coal bed methane, or CBM). Uncombusted methane is a greenhouse gas 25 times more potent than CO<sub>2</sub> over a 100-year timeframe.<sup>6</sup>

However, CSG differs from conventional gas and to a lesser extent shale gas in its geological location and extraction techniques. CSG is formed within a water-saturated coal seam, and held there by adsorption to the coal surface within the seam and pressure from the water. This pressure must be reduced to extract the gas. This is usually done by drilling into the seam and removing water, which allows gas to be released and brought to the surface.

In Australia, coal seams appropriate for commercial gas production vary in depth (starting generally at about 800 metres below ground), permeability and water saturation. During exploration, companies ascertain the specific composition of each gas field, and, depending on their findings, implement different methods to prepare wells for production ('completion'). Common methods of completion include horizontal drilling, where wells are drilled horizontally through rich coal seams; underreaming, where the drillhole is enlarged at the bottom; and hydraulic fracturing ('fracking'), where water, sand and chemicals (roughly 4-500,000 litres per well) are pumped into the seam to force open its cracks ('cleats'). This water is then recovered in a process known as 'flow back'.

A typical CSG field covers a much wider area and requires many more individual wells than a conventional gas field. This will usually mean that considerable quantities of energy, supplied by using some of the gas, are needed to pump the gas to a central collection point and also for pumping water and for fracking, if used. Queensland currently has approximately 4,500 CSG wells, of which 8 per cent have been 'fracked'. The proportion of 'fracked' wells is expected to increase to 10-40 per cent.<sup>8</sup>

Gas production begins by pumping out the water in the seams to reduce pressure and release the gas ('dewatering'). Initially, trace amounts of gas come up with the water ('produced water'). The proportion of gas increases as pressure within the well drops. The gas produced may be treated in various ways. During exploration, gas brought to the surface is commonly flared, releasing CO<sub>2</sub> instead of methane into the atmosphere. Gas may also be vented – released straight into the atmosphere as methane. During completion gas may be flared, reinjected, used to run equipment at the well site, and/or fed straight into a pipeline for direct use in the domestic gas market. During production gas is fed straight into a pipeline, for either use in domestic gas markets or, in years to come, processing to LNG for export. There is the potential for gas leakage at all stages of production. Venting and leaks are both forms of fugitive emissions.

**Table 1.** Comparisons between conventional gas, CSG, and shale gas<sup>7</sup>

	Conventional Gas	Coal Seam Gas (CSG)	Shale Gas
<b>Location</b>	Up to 5km below surface Gas is held in pores of sandstones and other porous rocks Higher pressure	200-1000m below surface Gas is adsorbed to coal surface Lower pressure	2km below surface, varies adsorbed on the rock surface, or as free gas in fissures or rock pores
<b>Composition</b>	90% methane varies significantly. Often contains significant quantities of other hydrocarbons ("natural gas liquids") and impurities, including CO <sub>2</sub> , hydrogen sulphide and water, all of which must be removed to meet pipeline quality specifications	Approx 97% methane varies. Often needs no processing to meet pipeline quality specifications	
<b>Extraction methods</b>	Vertical wells, occasional fracking	Vertical, horizontal, or directional drilling Underreaming Fracking	Extensive fracking combined with horizontal drilling

## 1.2 Gas processing and consumption

Once produced, gas can be consumed in several ways. Some will be used near the supply source to provide energy for further production, but most goes into pipelines for transport either to domestic gas markets or to LNG plants. Gas may need processing to meet pipeline quality specifications, and needs further processing to be converted to LNG.

Conventional natural gas commonly contains significant quantities of other hydrocarbons, including ethane, propane and butane, and impurities, including hydrogen sulphide and water, which are corrosive in pipelines and, in the case of hydrogen sulphide, very toxic. Separating these other hydrocarbons and impurities from methane is an energy intensive process. If the raw gas contains more than about 2 per cent by volume of CO<sub>2</sub>, this also must be removed by a process called acid gas stripping. The two major established gas processing plants in eastern Australia are located at Longford, where Gippsland gas is processed, and Moomba, where Cooper Basin gas is processed. Cooper Basin gas contains high levels of CO<sub>2</sub>, which is stripped and vented to the atmosphere. In the course of these various processes, some methane is also released to the atmosphere, the quantity depending on the technical sophistication of the process equipment. These stages mean that conventional gas processing can be a very emissions-intensive activity, from both combustion emissions and venting. CSG does not contain higher hydrocarbons and seldom contains CO<sub>2</sub> at levels which require removal to meet pipeline specifications. As it therefore requires very little processing, its processing emissions are consequently low.

Over recent decades Australia has become a major exporter of gas. Since there is no gas pipeline connecting Australia with gas markets in Asia, gas must be converted to liquefied natural gas (LNG) for export by ship. Conversion to LNG is an energy-intensive process which requires the gas to be cooled to minus 163 degrees Celsius, which is the liquefaction temperature. Before liquefaction, CO<sub>2</sub> must be reduced to very low levels, to prevent solidified CO<sub>2</sub> ('dry ice') from blocking pipes and valves. Incoming gas therefore undergoes acid gas stripping, during which stripped CO<sub>2</sub>, along with small quantities of methane, is vented to the atmosphere. Depending on the design of the LNG plant, the additional gas required to provide the required energy may equal up to 10 per cent of the energy in the LNG being exported. In addition, energy is needed to

transport gas from the field to the LNG plant, and from the plant to its ultimate destination.

## 1.3 Gas Transportation

Transporting gas to market requires pumping (compression), which uses energy and so produces emissions. Measurements made over the years have indicated that leakage from gas transmission pipelines in Australia, and from the high pressure gas mains supplying major users, such as power stations, is very low. However, leakage of gas from low pressure distribution mains, particularly in the older areas of major cities, can be quite high. Gas distribution leakage constitutes one of the large sources of fugitive energy emissions in the Australian greenhouse gas inventory.

## 2 Australia's CSG industry

The CSG industry in Australia is a little over 15 years old, with the first commercial production occurring in Queensland in the mid-1990s<sup>9</sup>. Within a few years, the size of the CSG resource had become apparent, and the Queensland Government developed policies to increase demand for gas in the state. These include the Queensland Gas Scheme, which required a defined percentage of total electricity supplied in the state to be sourced from gas fired generators. The percentage was set at 13 per cent starting in 2005, and was subsequently increased to 15 per cent from 2010<sup>10</sup>. The Scheme led to the commissioning of 625 MW of new gas fired generation capacity between 2001 and 2005 and a further 1,290 MW since 2006<sup>11</sup>. There has also been significant growth in demand for gas by industry, particularly in the mining and minerals processing sectors.

In February 2009 the QSN Link pipeline from Ballera gas processing plant in far south west Queensland to the Moomba gas processing plant in far north east South Australia started operating. This pipeline for the first time connected the Queensland gas fields with the large gas markets of south east Australia, which were already interconnected by pipelines. Currently, about 30 per cent of Queensland gas production is supplied, via the Moomba gas processing plant, to Sydney and other parts of NSW.<sup>12</sup> In 2010-11 CSG accounted for 76 per cent of all gas produced in Queensland. Reliable and up-to-date figures on national gas production are not available, but in 2009-10 Queensland CSG supplied just under 30 per cent of all gas produced in Australia. CSG is also produced in NSW from gas fields in the Sydney Basin, but currently production levels are very small – about 2 per cent of Queensland production.

A recent report for the Australian Energy Market Operator (AEMO), on gas resources in eastern Australia, estimates that proved and probable reserves of CSG total about 41 exajoules (EJ), of which 93 per cent are in Queensland and the remainder in NSW. Proved and probable reserves of conventional gas in eastern Australia are about 7.2 EJ, i.e. less than one fifth of CSG reserves<sup>13</sup>. This relative resource endowment is the reason that CSG is seen as being so important for the long-term availability of gas in eastern Australia. A proposed gas pipeline from the Queensland gas hub at Roma to Sydney, via the Gunnedah Basin, which is the largest known CSG resource in NSW, would enable the creation of a single CSG market across eastern Australia.

## 2.1 Current and future gas consumption in eastern Australia

In 2009-10 total market demand for gas in eastern Australia was about 656 PJ, of which 28 per cent (around 220PJ) was used for electricity generation, 44 per cent by large industrial users (including significant quantities used as petrochemical feedstock) and 28 per cent by retail consumers, including 17 per cent in the residential sector<sup>14</sup>.

This figure does not include gas used by the gas industry itself for processing raw gas to pipeline quality gas and in transmission and distribution activities transporting gas to consumers. It is difficult to estimate how much this might be, but it could be as much as 10 per cent of gas use by final consumers. Apart from electricity generation, and its use as petrochemical feedstock, the great majority of gas is used to provide heat, to supply steam, hot water, space heating and to drive a variety of industrial processes requiring intense heat, such as the manufacture of ceramics and glass. For the past three years there has been no growth in non-electricity consumption of gas in eastern Australia<sup>15</sup>.

The future domestic energy supply mix and the role of gas within that mix are highly uncertain, and this is reflected in the range of projections of future gas consumption. One source of uncertainty is future energy demand. After continually rising, demand for electricity peaked in 2009 and has since fallen, due in part to the impact of energy efficiency policies and the uptake of rooftop solar photovoltaic generation. Future demand growth is now expected to be significantly less than projected even a year ago<sup>16</sup>. Other sources of uncertainty are the cost trajectories of gas, coal and clean energy technologies, the future of climate policies such as the carbon price and the Renewable Energy Target, and the development of new uses for gas.

Different assumptions on all these points produce widely variable forecasts.

Among the gas industry's many published projections of future demand growth in Australia almost all rely on rapid growth in domestic gas-fired electricity generation. In contrast, analysts such as Standard and Poor's predict that high export prices for gas will reduce domestic demand for gas-fired generation, leading to greater reliance on coal and renewable energy.<sup>17</sup>

There appears little prospect for much future growth in the residential sector, as appliances become more efficient and houses better insulated. There may be some growth in production of petrochemicals and in some mineral processing activities. In the slightly longer term there may be increased use of gas as a fuel for heavy road transport (trucks and buses). Wide uptake of cogeneration and trigeneration plants could also drive faster growth in gas demand from commercial, industrial and even, if fuel cells are widely adopted, residential gas consumers.

The most recent projections, prepared by AEMO, modelled a comprehensive range of scenarios of gas use for electricity generation in the eastern Australian market<sup>18</sup>. Depending on assumptions, projections of gas demand for electricity generation range from as low as 130 PJ to as high as 600 PJ. Projections for 2030 range from 150 PJ to almost 1,200 PJ. Under most sets of assumptions, however, there is a doubling of gas use for electricity generation by 2020, and a further doubling by 2030. This component of gas demand, as modelled by AEMO, does not include gas used in cogeneration and trigeneration plants.

Overall, AEMO indicates that total gas consumption in eastern Australia may increase by between 19 per cent and 46 per cent over the period from 2010 to 2020. The absolute increase in consumption from 656 PJ in 2010 is projected to be between 120 PJ and 350 PJ, to reach levels of about 780 PJ and 1010 PJ respectively. Further consumption increase, at a somewhat higher rate, is projected to occur between 2020 and 2030. In almost all AEMO's scenarios the great majority of demand growth is projected to arise in Queensland<sup>19</sup>.

Production of gas from existing conventional gas fields is projected stay roughly constant, or perhaps decline slightly. This means that any increase in gas consumption will be supplied by CSG, mostly from Queensland, but possibly also from NSW. An increase of 350 PJ supplied by CSG will represent an increase of about 140 per cent on current levels of CSG production.

## 2.2 Gas production for LNG export

The various projections of growth in domestic demand for gas are dwarfed by the increased gas production which will be required to meet the requirements of LNG projects currently under construction and likely to be constructed. The confirmation of large CSG resources in Queensland has led to a boom in LNG projects and proposed projects. Three large projects are currently under construction on Curtis Island, near Gladstone. These are:

- + Queensland Curtis LNG, majority owned by Queensland Gas Company (wholly owned by the BG Group)
- + Gladstone LNG, a joint venture between Santos, Petronas, Total and KOGAS
- + Australia Pacific LNG, a joint venture between Origin Energy, Conoco Phillips and China Petroleum Corporation

The total capacity currently under construction at these three plants is 25 Mt p.a. of LNG, which is equivalent to about 1,500 PJ of gas; all are expected to come into operation between 2014 and 2016<sup>20</sup>. This capacity will be provided by two liquefaction trains at each of three plants. In total, 17 trains have been approved for construction at Gladstone by the Queensland government<sup>21</sup>. At least one plant is also being closely considered for construction at Newcastle in NSW. Construction of all of these will depend on securing contracts for the LNG produced and also securing access on commercially satisfactory terms to the required CSG production capacity. If they do all proceed, production of CSG will be well above 2,000 PJ by 2020, and under some scenarios, it could be more than 4,000 PJ by 2030<sup>22</sup>.

As noted above, LNG production is an energy intensive process. AEMO uses a total figure of about 14 per cent for gas consumption required to produce LNG for export<sup>23</sup>. Using this figure, production of 1,500 PJ of LNG would require gas consumption of 210 PJ, about equal to Queensland's current gas consumption for all purposes, and about 30 per cent of current gas consumption in eastern Australia.

Apart from its impact on production of CSG, and on Australia's energy consumption and consequent greenhouse gas emissions, the establishment of LNG export projects in Queensland will affect the price of gas throughout eastern Australia, by creating a link between international prices for LNG and prices in the domestic market. To simplify somewhat, an independent CSG

producer will be able to choose between supplying a domestic consumer or supplying an LNG plant, and the LNG company will be willing to pay a price equal to the price it receives for LNG, less costs of transport and of producing LNG, and a profit margin. The domestic consumer will have to match this price, and then also pay the cost of transporting the gas. Because eastern Australia is now a single connected wholesale gas market, the price paid for gas by LNG producers may eventually set the benchmark for wholesale gas prices throughout eastern Australia.

## 3 Greenhouse gas emissions from CSG

The production and use of CSG, as it is now evolving, poses two separate issues for Australian energy and emissions policy.

- + What might be the effect on Australia's total emissions of the boom in CSG production?
- + How do we ensure that CSG does not lock in high emissions, but plays a constructive role in the necessary transition to a zero/negative-emissions energy future?

In order to answer these questions it is necessary to know what emissions arise from all stages of the CSG fuel cycle: production, processing (either to pipeline gas or LNG) and, in the case of domestic use of CSG, transmission, distribution, final use and post-production. The relevant emissions fall into two broad groups:

- + combustion emissions, consisting mainly of CO<sub>2</sub>, with trace quantities of methane and nitrous oxide, from the use of gas, electricity and petroleum fuels to provide energy at all stages of the fuel cycle
- + fugitive emissions consisting of CO<sub>2</sub> arising from a variety of sources other than combustion of fossil fuels to provide energy and methane released to the atmosphere, also from a wide variety of sources and activities.

A recent paper by Hardisty et al. (2012) contains an extensive discussion of fugitive emissions from CSG field operations in Australia<sup>24</sup>. The paper proposes a best estimate of total emissions, including both combustion and fugitive, which is equivalent to 5.9 kt CO<sub>2</sub>-e/PJ gas supplied to an LNG plant. Subtracting 2.5 kt CO<sub>2</sub>/PJ of combustion emissions leaves an estimate of 3.4 kt CO<sub>2</sub>-e/PJ for fugitive emissions. The paper states that it uses a GWP of 21 and hence, if it is assumed that all fugitive emissions are methane (not

strictly accurate as there is some CO<sub>2</sub> from flaring), 3.4 kt CO<sub>2</sub>-e corresponds to 160 t methane/PJ.

The paper includes a discussion of possible higher emission scenarios, in which some of the methane released during well completions and related activities is vented directly to the atmosphere, rather than being flared. The paper estimates that if 20 per cent of methane were vented, not flared, total emissions from gas field operations, including both fugitive and combustion emissions, would increase by 24 per cent. With combustion emissions unaltered, this would imply a 42 per cent increase of fugitive emissions to 4.8 kt CO<sub>2</sub>-e/PJ, or roughly 230 t methane/PJ of gas supplied.

This figure is smaller than the most recent estimate by the USEPA of total 2010 fugitive emissions of methane from US gas field operations of 246 t methane/PJ of gas produced, on average<sup>25</sup>. This figure is equivalent about 1.3 per cent of gas produced being released to the atmosphere. It is a very large increase on the estimate contained in previous US national inventories, because, as the inventory report explains, ‘methodologies for gas well cleanups and condensate storage tanks were revised, and new data sources for centrifugal compressors with wet seals, unconventional gas well completions, and unconventional gas well workovers were used, relative to the previous Inventory’<sup>26</sup>. Specifically, while the USEPA had previously assumed that all gas from fraced wells was flared or captured; it now assumes that one third is directly vented to the atmosphere<sup>27</sup>.

Widely quoted papers by Cornell scientists Howarth et al. (2011, 2012) put fugitive emissions of methane from shale gas field operations even higher, at between 450 and 770 t methane/PJ gas produced, equivalent to 2.5 to 4.2 per cent of gas production<sup>28</sup> and 9.5 to 16 kt CO<sub>2</sub>-e/PJ. Howarth’s estimates significantly exceed those of the EPA primarily because Howarth et al. assumes both a high rate of methane venting during shale gas well completion (1.9 per cent, compared with 0.01 per cent for conventional gas), as well as a further 0.3-1.9 per cent loss for routine venting and equipment leaks at well sites, The Howarth estimates also exceed those of a number of other US studies, many of which are referenced and summarised in Howarth et al. (2012)<sup>29</sup>.

These other studies point out that Howarth figures correspond to gas production practice which makes few if any efforts to control emissions or use modern techniques. For example, a response from fellow scientists at Cornell (Cathles et al., 2012) pointed out that methane loss can be minimised through best-practice methods and technology<sup>30</sup>. Cathles et al. argue

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’<sup>31</sup>. The National Resources Defense Council has proposed ten methods and technologies to reduce methane emissions, ranging from ‘green completions’ (closed loop systems that capture and separate liquids and gases coming out of the well during completions instead of routing them to an open air pit or tank), to improved systems for reducing leaks from compressor seals, valves, storage tanks and pipelines. The NRDC estimates that these methods could cut methane leakage to 0.4 per cent of total gas production<sup>32</sup>.

Researcher	Fugitive emissions estimates	
Hardisty et al. (2012)	3.4 kt CO <sub>2</sub> e / PJ (low); 4.8 kt CO <sub>2</sub> e/PJ (high)	160 t methane/PJ 230 t methane/PJ
United States EPA (2012)		246 t methane/PJ
Howarth et al. (2011)	9.5-16 kt CO <sub>2</sub> e/PJ	450-770 t methane/PJ

There are several reasons to be cautious about the applicability of these findings to Australian CSG production. First, all of these studies rely on very limited data, so the accuracy and representativeness of these estimates remain highly uncertain. Second, Australian CSG production differs from American gas production in terms of extraction methods and technologies, regulatory frameworks, and processing procedures and equipment.

Because shale is less permeable and more brittle than coal, shale gas production always requires fracking. Because fracking and horizontal drilling are often combined in shale gas production, the extent of fracking can be much greater. This results in longer ‘flowback’ periods during completion, during which time shale wells may release ‘free gas’ – gas not adsorbed to the shale. Coal seams tend not to contain free gas. Instead, as the gas is adsorbed to the coal, gas may only be released when pressure within the seam is lowered. This means that the amount of gas released during completion would be expected to be smaller, more predictable and more easily managed, for CSG than for shale. Furthermore, Queensland regulations prohibit venting at field sites except in emergencies, and many Australian CSG companies have a policy of zero venting.

On the other hand, New South Wales does not prohibit venting at field sites, and, even in Queensland, given that large-scale CSG extraction requires several

hundred wells with associated production equipment and connections, there is obvious potential for multiple incidences of leakage, and an obvious challenge for emissions monitoring and mitigating systems. Neither state appears to demand as conditions of production that CSG companies implement all best practice technologies to ensure all methane emissions are correctly measured, monitored and mitigated. In NSW, concern about the weakness of the regulatory framework has led to the recommendation by a Parliamentary Committee that no further CSG production licenses be issued, and hydraulic fracturing be prohibited, pending further investigation and regulation<sup>33</sup>.

### 3.1 Comparing CSG and conventional natural gas: from production to pipeline

The tables on the two following pages provide a more detailed classification of the relationship between the various parts of the CSG fuel cycle and emission sources, and compare CSG with conventional natural gas. Natural gas production from offshore wells is not included, because it is not directly comparable with CSG. What are the implications for each policy issue for the comparisons shown in the tables? The two issues are considered in turn in the two following chapters.

It can be seen that potentially significant differences between CSG and conventional gas relate only to emissions at the upstream end of the fuel cycle, i.e. emissions arising from production of gas and processing it to pipeline quality. Pipeline gas produced from CSG is virtually identical with pipeline gas produced from conventional natural gas: it must meet the same performance specifications, and gas from the two sources is blended together to supply domestic markets. Hence emissions from the two sources in the course of pipeline transmission, gas network distribution and final use are not significantly different from each other.

In processing raw gas to pipeline quality, conventional natural gas on average produces considerably more emissions than CSG from both combustion and fugitive sources. The difference is attributable, as previously explained, to differences in the average composition of gas from the two sources. Of particular note is the fact that if the CO<sub>2</sub> concentration in raw gas is high, this will be a major source of emissions, making for high fugitive emissions.

For example, Longford, where most Gippsland gas is processed, is a large source of combustion emissions because of the need to separate out ethane and LPG (propane and butane). Energy use was 15.3 PJ in 2010-11<sup>34</sup>, which would have given rise to emissions of about 2.8 kt CO<sub>2</sub>/PJ of gas produced, if all energy use were allocated to gas production (less if some were allocated to LPG, which is a joint product). Moomba and Ballera, process less gas by volume than Longford, but are even larger sources of emissions, because Cooper Basin gas contains high levels of CO<sub>2</sub>. It can be calculated from data publicly reported by Santos that combustion emissions from energy use are about 5.5 kt CO<sub>2</sub>/PJ of gas produced and fugitive emissions about 17 kt CO<sub>2</sub>/PJ of gas<sup>35</sup>. On the other hand, some conventional gas fields contain low levels of impurities and higher hydrocarbons. This means that only limited processing is needed to achieve pipeline quality and emissions are correspondingly low. Kincora in Queensland and Otway in Victoria are processing plants in this category.

By contrast with conventional gas, the CSG resources exploited to date appear to have very low levels of impurities and no other hydrocarbons, meaning that they require very little processing to meet pipeline specifications<sup>36</sup>. Processing emissions from both energy combustion and CO<sub>2</sub> venting are therefore consistently very low, relative to the average for conventional natural gas.

A further source of emissions from processing both conventional gas and CSG is methane escaping from compressors, including compressor seals. The USEPA estimates that this source accounts for about 8 per cent of total methane emissions from the natural gas system<sup>37</sup>. Emissions from this source are not separately reported in the Australian emissions inventory, but by implication are assumed to be extremely low. It is quite possible that this very large difference can be explained by the greater age of the US gas pipeline system, its much greater complexity, and the greater diversity of owners, operators and regulators. Nevertheless, the size of the difference suggests that some further attention should be paid to this source of emissions in Australia, especially given the near certainty of much more gas being moved over longer distances in the coming years.

**Table 2**

*Sources of emissions for conventional gas and CSG when used to produce pipeline gas and to produce LNG*

Fuel cycle stage	Emission source category	Use as pipeline gas		Use as LNG	
		Onshore conventional gas	CSG	Onshore conventional gas	CSG
<b>Production</b>	Combustion	From gas and petroleum fuels used in exploration, drilling and pumping gas to a processing plant			
	Fugitive	Methane from well completions, liquids unloading, blowdowns, leakage from gathering pipelines, and other sources and CO <sub>2</sub> from flares			
<b>Processing</b>	Combustion	Energy intensive processes to remove impurities and, particularly, separate out ethane, propane, butane	Removal of (usually) low levels of impurities; no higher hydrocarbons occur with CSG	Very energy intensive process to make LNG, using gas and sometimes purchased electricity	
	Fugitive	CO <sub>2</sub> from acid gas stripping, methane from various activities and processes	Methane from various activities	CO <sub>2</sub> from acid gas stripping, methane from various activities and processes	Some CO <sub>2</sub> from acid gas stripping, methane from various activities and processes
<b>Transmission</b>	Combustion	Energy for compression (pumping)		Not occurring in Australia	
	Fugitive	Very low levels of methane from blowdowns		Not occurring in Australia	
<b>Distribution</b>	Combustion	Energy for compression (pumping)		Not occurring in Australia	
	Fugitive	Methane from leakage		Not occurring in Australia	
<b>Use</b>	Combustion	CO <sub>2</sub> , plus small amounts of unburnt methane and some nitrous oxide		Not occurring in Australia	
	Fugitive	Leakage on the customer's side of the meter		Not occurring in Australia	

**Table 3**

*Indicative comparison of relative magnitude of various emission sources*

Fuel cycle stage	Emission source category	Use as pipeline gas		Use as LNG	
		Onshore conventional gas	CSG	Onshore conventional gas	CSG
<b>Production</b>	Combustion	Usually small	Possibly large	Usually small	Possibly large
	Fugitive	Usually small	Possibly large	Usually small	Possibly large
<b>Processing</b>	Combustion	Often very large	Small	Very large	Very large
	Fugitive	Sometimes large	Small	Large to very large	Fairly small
<b>Transmission</b>	Combustion	Moderate		NA	
	Fugitive	Small		NA	
<b>Distribution</b>	Combustion	Moderate		NA	
	Fugitive	Quite large		NA	
<b>Use</b>	Combustion	Significantly lower than coal or petroleum products		NA	
	Fugitive	not estimated	same as conventional	NA	

Two sources of data on energy use and associated emissions of onshore gas field operations in Australia have been identified. Santos reports that in 2011 its Cooper Basin conventional gas field operations used 7.3 PJ of gas. Total production was approximately 120 PJ of gas (data from APPEA<sup>38</sup>), plus about 28 PJ of crude oil, condensate and LPG<sup>39</sup>. If, for simplicity, the energy use is allocated entirely to sales gas production, it equates to 6 per cent of the energy produced as gas. This would result in emissions of about 2.9 kt CO<sub>2</sub> /PJ of sales gas produced. The EIS for the Queensland Curtis LNG project states that annual production of 670 PJ of CSG will require consumption of 28 PJ for field operations, a slightly lower proportion of 4.4 per cent of gas supplied to the LNG plant. Emissions are estimated to be 2.5 kt CO<sub>2</sub>/PJ of gas supplied<sup>40</sup>. The Environmental Impact Statements for the other three major Queensland LNG projects do not provide useful information on estimated gas field operational energy consumption and consequent combustion emissions. On the basis of these limited data, it is not clear that combustion emissions from CSG field operations are necessarily higher than corresponding emissions from conventional gas production.

Reliable Australian data on fugitive emissions from gas field operations are virtually non-existent. Neither Exxon Mobil Australia (operator of major Gippsland Basin fields) nor Santos (operator of the Cooper Basin fields) mentions gas field fugitive emissions in their reporting of corporate emissions. The Australian National Greenhouse Gas Inventory reported 3.98 kt of fugitive methane emissions from gas production and processing in for 2009-10, which is equivalent to emissions of only 2 t/PJ of gas produced. This figure has been compiled from the National Greenhouse and Energy Scheme

(NGERS) reports of major gas producing companies<sup>41</sup>, which are based on application of the estimation methodologies specified in the NGERS *Measurement Determination*. The National Inventory Report states that ‘methodologies for facilities to estimate emissions were designed to be consistent with those used to compile the previous APPEA inventories [used to compile the National Inventory up to 2009]’<sup>42</sup>. These inventories used methods and emissions factors originally developed by the American Petroleum Institute (API) in the early 1990s (not the same as the more recent API *Compendium* of 2004), and for that reasons are unequivocally outdated, for conventional gas as much as for CSG.

Overall, a reasonable approach would be to take the estimate of gas field fugitive emissions by Hardisty et al. as a low end estimate, and the high end of the range proposed by Howarth et al. as a high end estimate. Table 4 shows these two estimates for emissions from CSG, using the estimate for gas field combustion emissions discussed above. It is assumed that CSG requires no processing other than dehydration to achieve pipeline quality, so processing combustion emissions are set at zero. In the absence of data on fugitive methane emissions from processing, these too are set at zero. The table also includes the estimates for Gippsland Basin (Longford) and Cooper Basin (Moomba/Ballera) gas production, discussed above. Cooper Basin total emissions are particularly high because of the very high emissions of vented CO<sub>2</sub>, from acid gas stripping.

The figures in Table 4 cover only those stages in the lifecycle of gas, from production to final use, where conventional gas and CSG are likely to differ. As previously explained, once gas enters a pipeline, it is

**Table 4**

*Estimated emissions arising from supplying gas into pipeline for domestic consumption (kt CO<sub>2</sub>-e/PJ gas supplied)*

Fuel cycle stage	Emission source category	Conventional gas		CSG	
		Cooper	Gippsland	High	Low
Production	Combustion	2.9	0.9	2.5	2.5
	Fugitive	0 <sup>(1)</sup>	0 <sup>(1)</sup>	16	3.4
Processing	Combustion	5.5	2.8	0 <sup>(2)</sup>	0 <sup>(2)</sup>
	Fugitive	17	0	0 <sup>(2)</sup>	0 <sup>(2)</sup>
Total emissions into pipeline		25.4	3.7	18.5	5.9

NOTES: (1) Set at zero in the absence of any information on this source of emissions. (2) Set at zero because CSG does not require significant processing to meet pipeline quality specifications.

effectively a single, uniform product, with identical emissions arising from transmission, distribution and final use, irrespective of whether it was originally extracted from a coal seam or a conventional gas reservoir.

On the basis of these figures it cannot be concluded that CSG is significantly more emissions intensive than conventional gas currently produced in Australia. That said, it should also be recognised that the Cooper Basin gas fields are unusual in eastern Australia in having very high levels of CO<sub>2</sub> raw gas. Gippsland gas processed at Longford is much more representative of the bulk of conventional gas produced in eastern Australia. Comparing high end estimates from CSG emissions to Gippsland gas would indicate a significantly more emission intensive industry.

A further note of caution relates to the Global Warming Potential value used for methane. So far as can be determined from the various sources, the figures in Table 4 have been calculated using a 100 year GWP value of 21. This is the value specified in the Kyoto Protocol, sourced from the Second IPCC Report. It has now been officially superseded by a value of 25, from the Fourth IPCC Report. As explained in Box A, the choice of a shorter period over which to compare methane with CO<sub>2</sub> would increase the relative impact of methane, but what the 'correct' value might be is an issue of continuing debate.

### ***Box A The debate over global warming potential (GWP) values***

Greenhouse gas emissions from coal seam gas are generally calculated by reference to the GWP factors for methane and CO<sub>2</sub>, multiplied by the estimated quantities of those gases emitted throughout the life cycle of CSG.

There is an ongoing debate about how to best account for the global warming impact of methane. According to the latest IPCC assessment, methane has a global warming potential (GWP) factor of 25 over a 100-year period, meaning that over 100 years it has 25 times the global warming impact of CO<sub>2</sub>. However, because methane breaks down faster than CO<sub>2</sub>, its GWP over shorter time periods is much higher over shorter periods and much lower over longer periods. The IPCC's GWP for methane over a 20-year period is 72; over a 500-year period it is 7.6. Although the 100-year timeframe is most commonly used, some accounting regimes rely on GWP factors from earlier IPCC assessments. For example, reporting under the first commitment period of the Kyoto Protocol uses a GWP factor for methane of 21, from IPCC 1996. The second commitment period makes use of the updated figure<sup>43</sup>. Some researchers argue that methane's short-term impact on global warming is higher than the IPCC's GWP would suggest; for example Shindell et al (2009) find GWPs for methane increase substantially when the impact of direct and indirect aerosol forcing is taken into account, leading to a 20-year period GWP for methane of 105<sup>44</sup>.

Choosing the appropriate GWP factor depends somewhat on the objective. Using the 100-year GWP factors of 21 or 25 for methane gives advantages in terms of consistency with common usage and recognition of methane's shorter lifetime in the atmosphere. There is an argument that the 20-year timeframe used by Howarth et al. is more relevant in the context of action needed in the next few decades to reduce global warming and particularly to avoid triggering irreversible tipping points in climate change. However, to the extent that this informs the debate over gas versus coal, using the 20-year GWP factor risks underplaying the long-term impact of CO<sub>2</sub>. The National Research Council warns that 'mitigation of the short-lived warming influences [such as methane] has sometimes been thought of as a way of "buying time" to put CO<sub>2</sub> emission controls into place. This is a fallacy... If the early action to mitigate methane emissions were done instead of actions that could have reduced net cumulative carbon emissions, the long term CO<sub>2</sub> concentration would be increased as a consequence'.<sup>45</sup>

### 3.2 Comparing CSG and conventional gas: full cycle from extraction to consumption

The full supply life cycle of gas includes not only production and processing, which have been discussed above, but also transmission and distribution. As shown in Table 2, each of these activities cause both energy combustion and fugitive emissions.

Based on energy consumption data from Australian Energy Statistics<sup>46</sup> and emissions data from the Australian Greenhouse Emissions Information System (AGEIS)<sup>47</sup>, it is estimated that supply of approximately 660 PJ of pipeline gas in eastern Australia in 2009-10 used about 6 PJ of energy (as gas) and emitted about 0.25 Mt CO<sub>2</sub>-e of methane as fugitive emissions. Total transmission emissions are equivalent to about 0.8 kt CO<sub>2</sub>-e/PJ of gas supplied.

Using the same sources, gas distribution in eastern Australia used 12 PJ. Fugitive emissions are reported on a national basis only, and totalled 3.35 Mt CO<sub>2</sub>-e of methane. These emissions arise only from gas supplied through distribution networks, which is reported by the ESAA as 386 PJ nationally and 354 PJ in eastern Australia<sup>48</sup>. Combining these figures gives total emissions from gas distribution of 10 kt CO<sub>2</sub>-e/PJ. Gas distribution emissions do not apply to gas used for centralised electricity generation, as power stations are supplied directly from the transmission system.

Combining these figures with emissions from combustion of gas by final users (51.3 kt CO<sub>2</sub>-e/PJ) gives estimates of life cycle emissions of gas in eastern Australia shown in Table 5. The average emission factor of black steaming coal combustion, for comparison, is 88.2 kt CO<sub>2</sub>-e/PJ<sup>49</sup>. This does not include full fuel cycle emissions arising from energy used to mine and transport coal and methane emissions from coal mines,

**Table 5**

*Life cycle emissions of conventional gas and CSG in different uses (kt CO<sub>2</sub>-e/PJ used)*

Gas type	Emissions level	To power station	To retail consumer
<b>Conventional gas</b>	High (Cooper)	77	87
	Low (Gippsland)	56	66
<b>CSG</b>	High	70	80
	Low	58	68

*Note: If, say, 3 kt CO<sub>2</sub>-e/PJ of the total 5.5 kt CO<sub>2</sub>-e/PJ of combustion emissions from processing Cooper Basin gas were allocated to the joint products, as discussed above, there would be a consequent reduction of 3 kt CO<sub>2</sub>-e/PJ in the Cooper emissions in the Table.*

which add another 4.6 kt CO<sub>2</sub>-e/PJ, making a total of 92.8 CO<sub>2</sub>-e/PJ.<sup>50</sup>

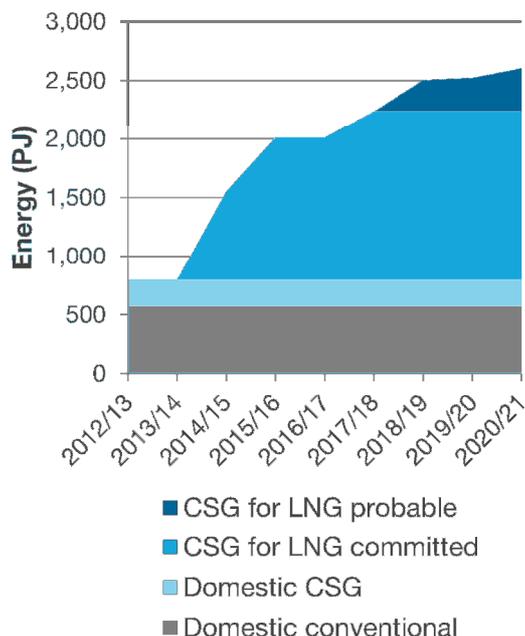
## 4 The impact of CSG on Australia's greenhouse gas emissions

While emissions resulting when LNG exported from Australia is used to provide energy will be the responsibility of the importing country, Australia will have to account for the emissions associated with CSG exploration, extraction, transmission and processing to LNG. The level of these emissions will of course depend on the quantity of LNG produced by each project and the emissions intensity of the project. At present three projects with total annual production capacity of about 25 million tonnes of LNG are firmly committed and under construction at Gladstone. A fourth project, Arrow LNG, is yet to commit, and is currently engaged in front end engineering design work. Queensland Curtis LNG, with two LNG processing trains committed, has stated that it may commit to a third train in the next few years. The additional capacity of these two undertakings is about 7.4 Mt LNG p.a., and can be classed as probable. It is conceivable that additional trains may be built at the other two committed projects, and proposals for several other, smaller LNG projects have been discussed. No account has been taken in the following analysis of these less certain possibilities.

Figure 4 below shows CSG production required to supply the committed and probable LNG capacity between now and 2020. It also shows the most recent available (for 2010) production of conventional gas and CSG in eastern Australia, as in Figure 1. Gas production includes both gas exported as LNG and gas used to supply energy for production and processing. The latter estimates are derived from information contained in the Environmental Impact Statements of the various projects, amended, in some cases, by more recent information contained in statements and publications accessible from the websites of the various projects. Compared with 2010, total gas production will be required to more than treble, and production of CSG to reach nine times its current level.

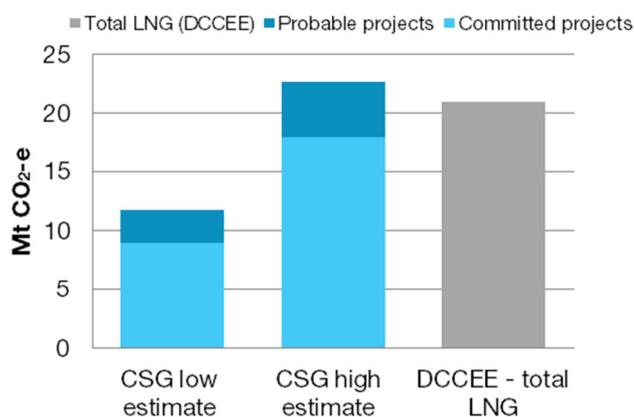
The additional emissions which are expected to arise from the committed and probable projects can be calculated from information contained in the various Environmental Impact Statements, and supplements. By 2020, additional emissions from committed projects will reach 9 Mt CO<sub>2</sub>-e, which equals about 1.7 per cent of Australia's emissions, excluding emissions from land use, land use change and forestry, in 2010. Probable projects would add a further 2.7Mt CO<sub>2</sub>-e.

**Figure 1**  
Production of CSG required to supply LNG projects, 2012-2020



As far as can be determined from the documentation provided, all these studies use estimates of fugitive emissions from CSG production similar to those quoted by Hardesty et al. (2012). If, instead, the High estimate of Table 4, above, is used, estimated emissions from committed CSG-LNG projects in 2020 would double to 18 Mt CO<sub>2</sub>-e, and probable projects would add a further 4.6 Mt CO<sub>2</sub>-e.

**Figure 2**  
Projected emissions from committed and probable projects in 2020, compared with DCCEE's projected fugitive emissions from all gas



Analysis by DCCEE in 2010 forecast fugitive emissions from Australia's entire gas sector to increase from 13 Mt CO<sub>2</sub>-e in 2010 to 21 Mt CO<sub>2</sub>-e in 2020<sup>51</sup>. DCCEE's analysis assumed CSG would make up only 15 per cent, or about 540 PJ, of total LNG production of about

3,600PJ. As Figure 4 shows, DCCEE's analysis underestimates the likely increase in CSG production. Moreover, as Figure 1 shows, it significantly underestimates the likely increase in CSG production emissions.

This has implications for Australia's emissions reduction task. Australia has a bipartisan commitment to emissions reductions of 5-25 per cent from 2000 levels by 2020. In absolute terms, this requires abatement of 160-270 Mt CO<sub>2</sub>-e in 2020. The boom in gas and coal production, and the consequent growth in emissions from both sectors, means that either the burden of emissions reduction will fall more heavily on other sectors or greater amounts of international permits will need to be imported.

## 5 Climate policy for CSG production and consumption

### 5.1 Emissions minimisation in CSG production

The potential impact of high emissions from CSG production on Australia's domestic emissions reveals the importance of ensuring these emissions are correctly measured, monitored and minimised. The lack of publicly available, independent research into the extent of methane leakage throughout gas production and processing, and the likelihood that current NGERs methods of calculating fugitive emissions are inaccurate require urgent attention from policy-makers.

There are several means by which CSG production emissions can be minimised. A carbon price creates a financial incentive for producers to reduce their emissions. However, its effectiveness depends both on accurate measurement of emissions, and the level and trajectory of the price itself. As noted above, some types of uncontrolled fugitive emissions, such as leakages from well and pipeline gathering systems, cannot be measured. In these cases it is essential that the regulatory framework for CSG production ensure industry-wide adoption of world's best practices, technologies and equipment to prevent emissions occurring. In cases where emissions can be measured, a carbon price must be applied to all emissions generated. This rewards companies that invest in methods to reduce their emissions—including those generated through energy consumption as well as direct production emissions.

Under the Government's Clean Energy Future package, the carbon price should ensure that CSG producers pay

for their emissions, once NGERs methods are updated and improved. Pricing carbon emissions is an important achievement. However, from 2015 the price will be linked to and set by the European Union's emissions trading scheme, which has seen significant price changes over the last few years. In the absence of a predictable long-term carbon price, the uncertainty surrounding the future trajectory of prices will discourage optimal levels investment in emissions minimisation.

Under the Coalition's climate plan, CSG producers may receive financial rewards for reducing their emissions below a baseline level and would pay a penalty for going above it. The level of reward and penalty is yet to be decided. This baseline should not be set at an individual company level but at world's best practice for the industry to reward early movers, and penalties need to be set high enough to incentivise emissions reductions within the industry.

The lack of bipartisan support for robust carbon pricing increases the importance of emissions-minimisation regulation.

As noted above, the emissions from Cooper Basin gas are considerably greater than those from CSG. A key difference is that the processing emissions from Cooper Basin gas are relatively easily measured and reported under the NGERs, so they are covered by the carbon price. In contrast, CSG production emissions may be more resistant to accurate measurement and necessitate best-practice regulation. That said, the emissions intensity of Cooper Basin gas would be greatly reduced were the stripped CO<sub>2</sub> to be re-injected into depleted gas reservoirs, a solution that could become more economically attractive under a higher carbon price. A few years ago Santos spent some time developing detailed plans for carbon geosequestration at Moomba, but decided not to proceed in 2010, when it became apparent that no power station with carbon capture capability would be built in Australia in the foreseeable future.

Other existing policies may also contribute to emissions reduction. BG Group International, the parent company of Queensland Gas Company, is a member of the Energy Efficiency Opportunities Program. Its 2011 Public Report contains the results of efficiency assessments undertaken at two of its gas fields, which identified several large, low cost opportunities to use energy more efficiently across its gas production portfolio<sup>52</sup>. These include increasing the efficiency of existing compressors by optimising control of their operation, and shifting from electric motor-driven to

direct gas engine-driven compressors in new installations.

## 5.2 Emissions reduction in domestic electricity generation

There are conflicting views about the role gas ought to play in Australia's electricity generation. The oil and gas industry has advocated strongly for greater gas-fired generation, stating that gas-fired generation creates emissions 50 per cent to 70 per cent lower than those created by the same capacity of coal-fired generation<sup>53</sup>. These percentages refer to the difference between direct combustion emissions from a CCGT power station and from either a black coal (50 per cent saving) or brown coal (70 per cent saving) fuelled power station (see Table 6, below). No account is taken of upstream emissions from extraction, processing and transport to the power station of either gas or coal. Opponents of gas argue that these upstream emissions are very high – so high, in fact, that when taken into account they would make gas more emissions intensive than coal<sup>54</sup>.

**Table 6** Efficiency and emissions from combustion: gas and coal fired power plants<sup>55</sup>

Power generation type	Thermal efficiency (%)	Emissions per unit of electricity (tonnes of CO <sub>2</sub> -e/MWh)
Australian Combined Cycle Gas Turbine (CCGT)	40-50	0.37-0.46
Australian Open Cycle Gas Turbine (OCGT)	23-34	0.50-0.80
Ultrasupercritical black coal (none in Australia)	46	0.7
Australian black coal plant	22-37	0.90-1.59
Australian brown coal plant	22-27	1.21-1.52
World average hard coal-fired plant	30	0.88
Gas with CCS	40-44	0.04-0.06
Coal with CCS	27-31	0.10-0.15

Neither of these two positions is supported by the information in this paper. It is obvious that comparing the emissions impact of alternative generation technologies does not fully account for all emissions caused by using gas. On the other hand, this paper

demonstrates that, even if the highest level of fugitive emissions from CSG production, as proposed in the work of Howarth et al., is adopted, life cycle emissions from use of CSG—as currently measured—are still less than life cycle emissions from use of coal (using a methane GWP value of 25). There remain uncertainties about whether the current methodologies cover all emissions, including possible post-production leakage.

As discussed above, the future role of gas in the domestic electricity market is subject to many uncertainties. It is important to recognise that in this environment the type of generation actually built will be determined by the operation of the market and its interaction with the carbon price and the Renewable Energy Target.

Investment in electricity generation needs reasonable price and policy certainty over a time period of at least 10-15 years. The transition from today's high emissions electricity generation to a low- and ultimately zero- and/or negative-emissions electricity sector requires certainty about the long-term emissions requirements of new generation. For CSG to act as a true 'bridging fuel' in electricity supply, policies must provide investors with a clear signal toward continually reducing emissions. A carbon price is an appropriate policy tool; however, as noted above, Australia's carbon price regime will be exposed to weaknesses in the European Union's emissions trading scheme (ETS), and complementary measures are necessary. In response to the volatility in the EU ETS the UK Government has put in place a minimum carbon price on electricity generation, and proposed emissions performance standards that would ensure new coal plant is equipped with carbon capture and storage.

Stringent emissions performance standards (EPS) for new power generators are also necessary to address ongoing uncertainty in Australia's electricity sector, and avoid the construction of new power plants that could undermine national climate change mitigation goals and/or lead to stranded assets and higher costs in future.

The Climate Institute supports the introduction of an emissions performance standard for all new non-peaking gas plants, set at 0.2 tCO<sub>2</sub>-/MWh within 15 years after construction. This allows combined-cycle

gas plants to be deployed without carbon capture and storage (CCS) for the rest of the decade, but sets a clear requirement – and investment signal - for CCS within the following decade.<sup>56</sup>

Without these policies in place, Australia risks severely reducing efficiency and increasing the cost and emissions of electricity production. The aggregate power system cost impact of ongoing policy uncertainty between the Government, Opposition and the Greens amounts to \$4.7 billion with pollution pricing and a similar amount without carbon pricing. As a result, electricity prices are around 2.5 per cent higher than if there was policy certainty.<sup>57</sup>

## Recommendations

1. The Commonwealth Government should immediately commission, with funding from the CSG-LNG industry, robust independent research into the emissions profile of CSG production in Australia, with a particular focus on emissions from CSG extraction including emissions after production ceases.
2. Emissions measurement and estimation methods in the NGERs Guidelines should be updated on the basis of the research findings.
3. Regulation of CSG production should be nationally harmonised, and should enforce best practices. Regulation is appropriate in the absence of bipartisan support for robust pollution pricing and for practices, technologies and equipment where accurate emissions measurements or estimates are lacking or impractical.
4. Introduce emissions performance standards for power generators. All non-peaking gas plants must be retrofitted to 0.2 tCO<sub>2</sub>-/MWh within 15 years after construction.<sup>58</sup>
5. In addition, under the Coalition's climate policy, CSG production emissions above best practice should be strongly penalised to incentivise investment in emissions reductions or offsets. Penalties should be set at levels consistent with reducing national emissions to the bipartisan supported 2020 target range.

## Endnotes

- <sup>1</sup>Note that this comparison is per petajoule of energy produced according to National Greenhouse Accounts Factors, and does not compare CSG and coal in power stations of varying performance.
- <sup>2</sup>At this stage, peaking plants pose less of a risk of locking in long term polluting assets. The Climate Institute also supports emission performance standards for coal-fired power stations. See Southern Cross Climate Coalition (2011) 'A Policy Platform for a Low Pollution Economy'. Available online at <[http://www.climateinstitute.org.au/verve/\\_resources/SCCC\\_a\\_policy\\_platform\\_for\\_a\\_low\\_carbon\\_economy\\_-\\_policy\\_brief.pdf](http://www.climateinstitute.org.au/verve/_resources/SCCC_a_policy_platform_for_a_low_carbon_economy_-_policy_brief.pdf)>
- <sup>3</sup>Australian Energy Market Operator (2011), *Gas Statement of Opportunities 2011*. Available online at <<http://www.aemo.com.au/en/Gas/Planning/Gas-Statement-of-Opportunities>>
- <sup>4</sup>Queensland Government, Department of Employment, Economic Development and Innovation (2011), *2011 Gas Market Review*. Available online at <<http://www.deedi.qld.gov.au/energy/gas-market-rev.htm>>
- <sup>5</sup>All climate scenarios that avoid warming beyond 1.5-2 degrees Celsius require negative global emissions after 2050.
- <sup>6</sup>S. D. Solomon et al. (eds.) (2007), *Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*, Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.
- <sup>7</sup>Jay Rutovitz et al. (2011), 'Drilling Down – Coal Seam Gas: A Background Paper', Institute for Sustainable Futures for the City of Sydney Council, University of Technology; Henry D. Jacoby, Francis M. O'Sullivan, and Sergey Paltseva (2012), 'The Influence of Shale Gas on US Energy and Environmental Policy', *Economics of Energy & Environmental Policy*, Vol. 1, no. 1.
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- <sup>9</sup>Queensland Government, Department of Employment, Economic Development and Innovation (2011), *op. cit.*
- <sup>10</sup>See Queensland Government, 'Queensland Gas Scheme' [online guide]. Available at <<http://www.business.qld.gov.au/industry/energy/queensland-gas-scheme>>
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- <sup>12</sup>Calculated from data in recent issues of *Weekly Gas Market Report*, published by the Australian Energy Regulator. Available online at <<http://www.aer.gov.au/node/451>>
- <sup>13</sup>Core Energy Group Ltd (2012), *Eastern & Southern Australia: Existing Gas Reserves & Resources*. Available online at <<http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/Gas-Reserve-Update>>
- <sup>14</sup>Australian Energy Market Operator (2011), *op. cit.*
- <sup>15</sup>Hugh Saddler and Graham Anderson (2012), *CEDEX Carbon Emissions Index*, Pitt and Sherry, May 2012.
- <sup>16</sup>Australian Energy Market Operator, (2012) *2012 National Electricity Forecasting Report*.
- <sup>17</sup>Standard & Poors (2012), *Can Gas Smooth Australia's Transition From Coal Or Will Renewables Leap Ahead?*
- <sup>18</sup>Australian Energy Market Operator (2011) *op. cit.*
- <sup>19</sup>*Ibid.*
- <sup>20</sup>Queensland Government, *2011 Gas Market Review*.
- <sup>21</sup>SKM MMA modeling for 2011 Gas Review Queensland [online document]. Available online at <[http://www.deedi.qld.gov.au/documents/energy/102145\\_Gas\\_Market\\_Modelling\\_for\\_the\\_2011\\_GMR\\_-\\_Final\\_Report\\_29-7-11-3.pdf](http://www.deedi.qld.gov.au/documents/energy/102145_Gas_Market_Modelling_for_the_2011_GMR_-_Final_Report_29-7-11-3.pdf)>
- <sup>22</sup>Australian Energy Market Operator (2011) *op. cit.*
- <sup>23</sup>*Ibid.*
- <sup>24</sup>P. Hardisty, T.S. Clark and R.G. Hynes (2012), 'Life Cycle Greenhouse Gas Emissions from Electricity Generation: A Comparative Analysis of Australian Energy Sources.' *Energies* 5, 872-897.
- <sup>25</sup>Calculated from data in United States Environmental Protection Agency (2012), *Inventory of US Greenhouse Gas Emissions and Sinks*.
- <sup>26</sup>*Ibid.*, 10-1.
- <sup>27</sup>M. Fulton et al. (2011), 'Comparing Life-Cycle Greenhouse Gas Emissions from Natural Gas and Coal', Deutsche Bank Group and WorldWatch Institute, 25 August 2011 [online report]. Available online at <[http://www.worldwatch.org/system/files/pdf/Natural\\_Gas\\_LCA\\_Update\\_082511.pdf](http://www.worldwatch.org/system/files/pdf/Natural_Gas_LCA_Update_082511.pdf)>.
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- <sup>29</sup>Robert W. Howarth, Renee Santoro and Anthony Ingraffea (2012) 'Venting and leaking of methane from shale gas development: response to Cathles et al.', *Climatic Change* 113:2, 537-549.
- <sup>30</sup>Lawrence M Cathles et al. (2012), 'A commentary on "The greenhouse-gas footprint of natural gas in shale formations" by R.W. Howarth, R. Santoro, and Anthony Ingraffea', *Climatic Change* 113:2, 525-535.
- <sup>31</sup>*Ibid.*
- <sup>32</sup>Susan Harvey, Vignesh Gowrishankar and Thomas Singer (2012), 'Leaking Profits: The US Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste', Natural Resources Defense Council. Available online at <<http://www.nrdc.org/energy/leaking-profits.asp>>.
- <sup>33</sup>New South Wales Parliament (2012), *Inquiry into coal seam gas*. Legislative Council General Purpose Standing Committee No. 5.
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- <sup>35</sup>Santos (2012), *Sustainability Report 2011*. Available online at <[http://www.santos.com/library/Sustainability\\_Report\\_2011.pdf](http://www.santos.com/library/Sustainability_Report_2011.pdf)>
- <sup>36</sup>The Environment Impact Statements for each of the four major Queensland LNG projects report CO<sub>2</sub> concentrations of 1% or less. Pipeline gas can contain up to about 2% CO<sub>2</sub>.
- <sup>37</sup>US EPA (2012), *op. cit.*, 3-47.
- <sup>38</sup>Australian Petroleum Production and Exploration Association (2012), *Statistics*. Available online at <<http://www.appea.com.au/oil-a-gas-in-australia/statistics.html>>
- <sup>39</sup>Santos (2012), *op. cit.*
- <sup>40</sup>Queensland Gas Company Ltd., 2008. *Queensland Curtis LNG Environmental Impact Statement*, Vol. 7. Available online at <[http://www.qgc.com.au/01\\_cms/details.asp?ID=427](http://www.qgc.com.au/01_cms/details.asp?ID=427)>
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- <sup>42</sup>*Ibid.*, p. 102.
- <sup>43</sup>United Nations, Report of the Conference of the Parties serving as the meeting of the Parties to the Kyoto Protocol on its seventh session, held in Durban from 28 November to 11 December 2011 Addendum Part Two, FCCC/KP/CMP/2011/10/Add.1 (2011) [online document] <<http://unfccc.int/resource/docs/2011/cmp7/eng/10a01.pdf>>, accessed 12 April 2012
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- <sup>46</sup>Bureau of Resource and Energy Economics (2011). *Australian Energy Statistics: Energy Update*, Table F.

<sup>47</sup> Department of Climate Change and Energy Efficiency (2011) National Greenhouse Gas Inventory [online database]. Available at <http://ageis.climatechange.gov.au/>

<sup>48</sup> ESAA (2011), *op. cit.*, Table 5.5.

<sup>49</sup> Department of Climate Change and Energy Efficiency (2011). *National Greenhouse Accounts Factors*.

<sup>50</sup> See endnote 1.

<sup>51</sup> Australian Government, Department of Climate Change and Energy Efficiency (2010), *Australia's Emissions Projections 2010 - Fugitive Emissions Projections* [technical paper] <<http://www.climatechange.gov.au/en/publications/projections/australias-emissions-projections/fugitive-emissions.aspx#oil>>

<sup>52</sup> Queensland Gas Company, *2011 Energy Efficiency Opportunities Report*. Available at <[http://www.qgc.com.au/media/125352/01--eeopublicreport--energy\\_efficiency\\_ops.pdf](http://www.qgc.com.au/media/125352/01--eeopublicreport--energy_efficiency_ops.pdf)>

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<sup>54</sup> Beyond Zero Emissions (2012), 'Worley base case baseless but coal seam gas still worse than coal', media release 28 March 2012.

<sup>55</sup> Table compiled from IEA Energy Technology Network gas fact sheet [http://www.iea-etsap.org/web/E-TechDS/PDF/E02-gas\\_fired\\_power-GS-AD-gct.pdf](http://www.iea-etsap.org/web/E-TechDS/PDF/E02-gas_fired_power-GS-AD-gct.pdf); IEA, Power Generation from coal, [http://www.iea.org/ciab/papers/power\\_generation\\_from\\_coal.pdf](http://www.iea.org/ciab/papers/power_generation_from_coal.pdf), and ACIL Tasman, 'Calculation of energy costs for the 2011-12 BRCI Final Decision', report prepared for the Queensland Competition Authority, 30 May 2011 Tables 28-32 <http://www.qca.org.au/files/ER-NEP1112-ACIL-FinalReport-CostofEnergy11-12BRCI-0511.PDF>; Global Carbon Capture and Storage Institute, personal communication 8 May 2012.

<sup>56</sup> Exemptions from this rule include peaking gas plants that run for less than 10 per cent of the time. The Climate Institute also supports EPS for coal-fired plant: see <[http://www.climateinstitute.org.au/verve/\\_resources/wwftci\\_emissionstandardssubmission\\_dec2010.pdf](http://www.climateinstitute.org.au/verve/_resources/wwftci_emissionstandardssubmission_dec2010.pdf)>

<sup>57</sup> Paul Simshauser and Tim Nelson (2011), 'Carbon taxes, toxic debt and second-round effects of zero compensation: the power generation meltdown scenario', *AGL Applied Economic and Policy Research Working Paper No.26*, (Sydney: AGL).

<sup>58</sup> At this stage, peaking plants pose less of a risk of locking in long term polluting assets. The Climate Institute also supports emission performance standards for coal-fired power stations. See Southern Cross Climate Coalition (2011) 'A Policy Platform for a Low Pollution Economy'. Available online at <[http://www.climateinstitute.org.au/verve/\\_resources/SCCC\\_a\\_policy\\_platform\\_for\\_a\\_low\\_carbon\\_economy\\_-\\_policy\\_brief.pdf](http://www.climateinstitute.org.au/verve/_resources/SCCC_a_policy_platform_for_a_low_carbon_economy_-_policy_brief.pdf)>